SUNCOR
ENERGY

energy for the future

2004 annual report

expanding beyond

Suncor Energy Inc. is an integrated energy company strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. Since pioneering the industry in 1967, we have more than quadrupled our oil sands production and marketing with a three-fold strategy: develop multiple sources of bitumen supply; employ a staged approach to expanding our upgrading technology; and integrate our products into the growing North American marketplace. As we enter a new phase of expansion, we will continue to build on the assets, experience and long-term strategy that have driven profitable growth and strong returns for Suncor shareholders.

financial highlights

Suncor's strong financial returns are evidence of our ability to generate shareholder value by delivering on strategic growth opportunities.

Production
(thousands of barrels of oil equivalent per day)

	00	01	02	03	**04**
Natural Gas	40.5	33.4	33.7	34.9	**36.8**
Oil Sands	113.9	123.2	205.8	216.6	**226.5**
Total	154.4	156.6	239.5	251.5	**263.3**

Net Earnings
($ millions)

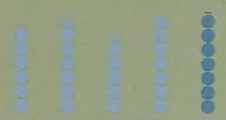
	00	01	02	03	**04**
	361	376	749	1 075	**1 100**

Cash Flow from Operations/ Net Debt
($ millions)

	00	01	02	03	**04**
Cash flow from operations	958	831	1 440	2 079	**2 021**
Net debt	2 236	3 143	2 671	2 091	**2 159**

Suncor maintained relatively steady net debt while redeeming $493 million of preferred securities in 2004.

Return on Capital Employed
(per cent)



	00	01	02	03	**04**
	16.3	17.7	14.6	18.4	**19.1**

Excludes major project costs until new assets are brought into operation.

Other Key Indicators

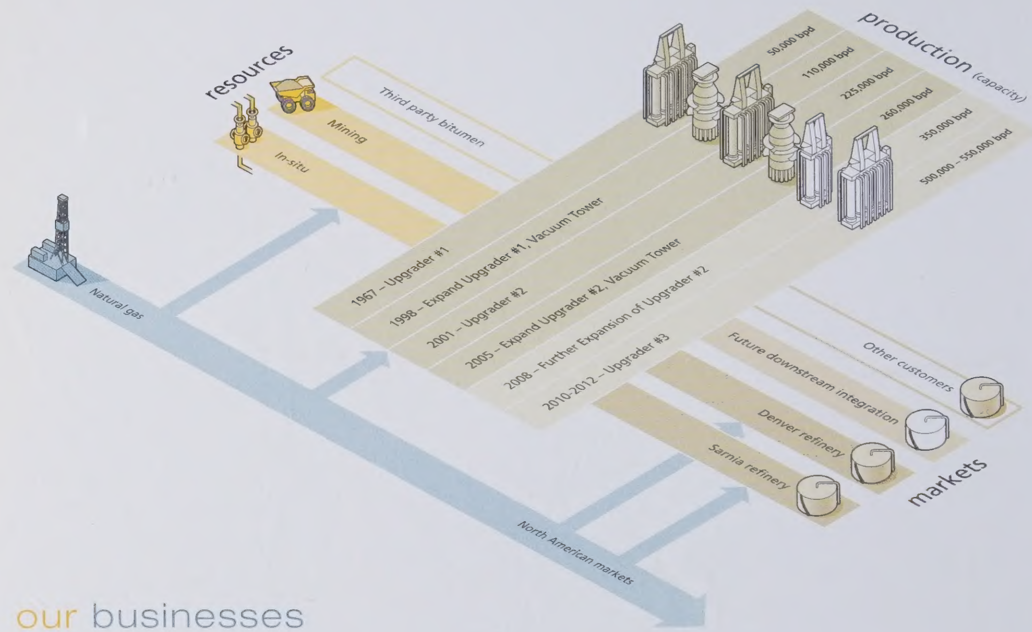
Year ended December 31 ($ millions)	**2004**	2003	2002	2001	2000
Financial					
Revenues	**8 621**	6 571	5 032	4 294	3 484
Capital and exploration expenditures	**1 846**	1 316	877	1 678	1 998
Total assets	**11 804**	10 501	9 011	8 430	7 174
Dollars per Common Share					
Net earnings attributable to common shareholders – basic	**2.40**	2.41	1.61	0.76	0.74
Net earnings attributable to common shareholders – diluted	**2.36**	2.24	1.58	0.75	0.73
Cash flow from operations	**4.46**	4.62	3.22	1.87	2.16
Cash dividends	**0.23**	0.1925	0.17	0.17	0.17
Market Price of Common Stock at December 31 (closing)					
Toronto Stock Exchange (Cdn$)	**42.40**	32.50	24.70	26.20	19.15
New York Stock Exchange (US$)	**35.40**	25.06	15.67	16.45	12.85
Key Ratios					
Debt to debt plus shareholders' equity (%)	**31.4**	36.3	44.2	53.5	48.1
Net debt to cash flow from operations (times)	**1.1**	1.0	1.9	3.8	2.3
Return on shareholders' equity (%)	**23.8**	27.7	24.4	14.6	16.0

This annual report contains forward-looking statements that involve risks and uncertainties. Actual results may differ materially. See page 53 for additional information. All financial information is reported in accordance with Canadian generally accepted accounting principles (GAAP) and in Canadian dollars unless noted otherwise. Financial measures not prescribed by GAAP include cash flow from operations, return on capital employed and cash operating costs. See page 51 for more details. Natural gas converts to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries and joint-venture investments, unless the context otherwise requires. Suncor has provided cost estimates for projects that, in many cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amount is expected to differ and the difference could be material.

about suncor

Today, Suncor has four major business divisions in Canada and the United States, with more than 4,500 employees. Our core oil sands business is supported by conventional natural gas production in Western Canada and downstream refining, marketing and retail businesses in Ontario and Colorado. As we work to responsibly meet the demands of today's energy market, we are also investing in low environmental impact renewable energy for the future.

Suncor's large resource base, low-cost production and secure market access are the foundation of an integrated strategy aimed at growing profitably and generating consistent, high returns on our capital investments. We're building on the energy of our past successes with a staged approach to expanding our operations. Our goal: production of more than half a million barrels of oil per day.



our businesses

Oil Sands

The foundation of Suncor's business and future growth strategy is the Athabasca oil sands, located near Fort McMurray, Alberta. The oil sands business recovers bitumen (a tar-like, heavy oil) through conventional surface mining and steam injection technologies, and upgrades it into refinery feedstock and diesel fuel. Future plans remain focused on increasing production, controlling operating costs and reducing environmental impacts.

Natural Gas and Renewable Energy

Based in Calgary with operations in Western Canada, this business manages development and production of natural gas to provide a price hedge against internal consumption at our oil sands and refining operations. Natural Gas and Renewable Energy also supports our sustainability goals by managing investments in wind energy projects and developing strategies to reduce greenhouse gas emissions.

Energy Marketing and Refining – Canada

Suncor's Canadian downstream operations market the company's natural gas production and a range of crude oil products to commercial and industrial customers. Products from our Sarnia, Ontario refinery are sold to commercial customers in Canada and the northeastern United States, and to retail customers in Ontario through more than 500 Suncor-owned, Sunoco-branded and joint-venture operated service stations.

Refining and Marketing – U.S.A.

Suncor's Denver-area refinery and its Phillips 66-branded retail stations connect us to industrial, commercial and retail markets in the U.S. Rocky Mountain region. The Denver team is leading Suncor's efforts to further expand into the growing U.S. energy market.

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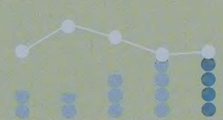

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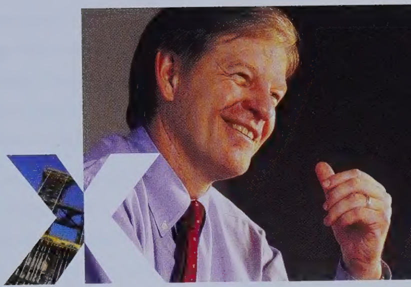
Total Return on Investment

Suncor's return to shareholders has outperformed the TSX Integrated Oils and the S&P 500. An investment of $100 in Suncor on December 31, 1992 – the year we became publicly traded – would have grown to more than $1,800 by the end of 2004.

Assumes reinvestment of dividends.



Rick George
president and chief executive officer

moving forward

Energy for the Future

Energy for the future – that was the vision when Suncor emerged as a publicly traded company in 1992. We weren't a big company, but we saw big potential. With the key assets of a large resource base, a single oil sands upgrader and the most experienced operating team in the business, we laid out a vision for growth based on our core oil sands operations – growth that we believed would provide long-term value for shareholders while making Suncor a major player in the North American energy industry.

Since then, we've made significant progress toward our goals. Suncor's daily oil sands production has more than tripled; our production costs have declined to a point where we are now among the lowest cost producers in North America; and we have expanded our reach into the marketplace with new refining and retail assets. Most importantly, we've delivered on our promise of shareholder value. Since becoming publicly traded, Suncor has grown from a market capitalization of about $1 billion to more than $19 billion at the end of 2004, providing shareholders an annual average return of more than 25%. In delivering on our vision of energy for the future, Suncor has defined success in a new type of crude oil business, not by exploring increasingly remote corners of the globe, but through harnessing technology to manufacture energy products. Like other manufacturing processes, our success is built on securing raw materials, focusing on high volume, low-cost production methods and developing markets for our products.

These are the three pillars of Suncor's proven strategy – a strategy we will build on as we enter a new phase of growth.

First, we are developing our large resource base through multiple sources of bitumen supply – heavy oil that is the building block of our product slate. Suncor is tapping a potential 11 billion barrels of oil on its leases through truck and shovel mining and steam injection in-situ technology. We are also supplementing our own bitumen recovery through innovative third-party bitumen supply agreements, providing greater flexibility and reliability to our resource feedstock.

Second, Suncor is increasing production. At our oil sands operations, we aim to increase crude production through staged investments in technology to upgrade raw bitumen into crude oil products that attract higher demand and a higher market value. We are now in the process of expanding our second upgrader and are steadily progressing plans for a third upgrader and production capacity of more than half a million barrels per day (bpd). We plan to increase current production capacity by more than 50% in 2008 and double it by 2012. In our natural gas business, targeted production growth supports a "price hedge" – producing more natural gas than we purchase to offset the impact of volatile prices for natural gas used in our oil sands and refining operations.

Third, Suncor is integrating our slate of products into the growing North American energy market through our own refining facilities and long-term marketing agreements, helping to reduce vulnerability to supply and demand imbalances for oil sands crudes.

This three-part strategy, together with a focus on operational excellence and a broad-based and long-term vision of managing environmental and social performance, add up to the Suncor formula that has delivered long-term shareholder value. In 2004, we continued to build on that formula.

2004 Highlights

With solid production in both the oil sands and natural gas businesses, Suncor set a new production record of 263,300 barrels of oil equivalent per day (boe/d), up from 251,500 boe/d in 2003. Oil sands production averaged 226,500 bpd, including 10,900 bpd from stage one of our Firebag in-situ operations, which began producing in January of 2004. At our base operations, we maintained our focus on controlling cash operating costs which, at $11.95 per barrel, were slightly over our original 2004 target range of $10.75 to $11.75 per barrel.

While high natural gas prices continued to challenge our operating costs, it's important to note they were a net benefit to Suncor's bottom line as our natural gas business reached record production of 200 million cubic feet per day (mmcf/d), well in excess of 2004 average purchases of about 130 mmcf/d.

In downstream operations, Suncor launched major upgrades at both our Sarnia and Denver refineries. The modifications are planned to ensure Suncor meets low sulphur fuels regulations while also allowing us to process oil sands sour crude at both facilities. Both the Ontario and Colorado operations also advanced improvements to retail sites to help protect margins and market share in this highly competitive business.

In 2004, we also furthered our efforts to expand Suncor's renewable energy business with the opening of the 30-megawatt Magrath Wind Power Project in southern Alberta. Magrath, Suncor's second wind power project, is expected to offset the equivalent of 82,000 tonnes of carbon dioxide per year, a key part of managing our greenhouse gas emissions as we increase oil sands production.

Record production, combined with high commodity prices, strong refining margins and tight management of capital costs contributed to a return on capital employed of 19% and net earnings that, for the second consecutive year, topped the $1 billion mark. Cash flow from operations in 2004 totalled more than $2 billion, helping Suncor to maintain relatively steady year-over-year net debt levels while redeeming nearly $500 million in preferred securities and investing $1.8 billion in our operations and growth plans.

For many companies, these accomplishments would describe a very successful year. However, Suncor sets high standards and we recognize that in some areas, we fell short of our own, and shareholder, expectations. Oil sands production was lower than capacity due to unscheduled maintenance and several smaller operational issues across our businesses kept Suncor from taking full advantage of high commodity prices and strong refining margins. We know we can do better and we will be working hard to improve our performance as we look to 2005 and beyond.

Expanding Beyond – Suncor's Plans and Priorities

Looking at the coming year, we see commodity price fundamentals remaining strong due to expected high demand for crude oil, low incremental capacity available to the market and continuing concern about security of supplies from key producing countries. The benefits of strong commodity prices could continue to be offset somewhat by a strong Canadian dollar that reduces the price we receive based on U.S. dollar benchmarks. While we cannot control commodity prices or exchange rates, we will continue to focus on areas we can control: ensuring safe, reliable operations, managing operating costs, expanding our integrated operations and maintaining a strong balance sheet. These will be the priorities for 2005:

- **Focus on safety.** As we work to deliver our goals for 2005 and build on Suncor's long-term strategy, one priority stands out above all others: the safety of our employees and contractors. Damaged equipment can be repaired or replaced; people cannot. I am pleased with improvements in Suncor's safety record in 2004 and will be working with Suncor's management to ensure we continue to improve in 2005.
- **Return oil sands operations to full production.** Unfortunately, Suncor got off to a rocky start to 2005 with a fire at our oil sands facility in Upgrader 2 in January. Work to restore our oil sands operation to full production following the January fire will be the focus for much of the Suncor oil sands team. During this time, oil sands base plant production is expected to be reduced to about 110,000 bpd. While insurance coverage is expected to help mitigate financial impacts, our goal is full production and we will be working to

complete the recovery work as safely and quickly as possible. We also plan to bring forward maintenance previously scheduled for the fall of 2005, with a goal of resuming full production rates during the third quarter.

- Build for future growth. While recovery and maintenance work is under way at oil sands, growth projects are expected to remain firmly on course. The near-term setback from the fire does not detract from Suncor's long-term strategy for growth and delivering value to our shareholders. We will continue to build on our resource development, production expansion and market integration strategy in 2005. Expansion at oil sands is expected to drive Suncor to a new oil sands milestone: production capacity of 260,000 bpd by year-end 2005. Construction is on the homestretch and expansion projects remain on schedule and on budget. Suncor's next planned phase of expansion is also expected to make important strides in 2005. Fabrication of major vessels and site preparation to support our goal of 350,000 bpd in 2008 is under way.

  These expansions at oil sands are important steps on our way to reaching a goal of producing 500,000 to 550,000 bpd in the 2010 to 2012 time frame. We expect to mark another major milestone on our path toward that goal in 2005, when we file a regulatory application for a third upgrader. Realizing this goal will not only increase total production volumes, it will also provide ongoing production during periods of maintenance. This advantage is clearly underlined by the benefits we currently see with continuing production from Upgrader 1 while recovery and maintenance work is under way at our oil sands plant.

  In our downstream operations, where oil sands supply connects to the demand of a growing North American energy market, we plan to substantially advance modifications to both the Denver and Sarnia refineries to comply with low-sulphur fuels regulations in advance of 2006 deadlines. We also plan to modify both refineries to accommodate a broader slate of oil sands products. As oil sands production expands, Suncor will continue to look for new integration opportunities, including potential joint-ventures or asset acquisitions.

- Maintain a strong balance sheet. Suncor will maintain a disciplined approach to balancing cash flow and net debt as we plan capital investment of $2.5 billion in 2005 to support our growth plans. Impacts from hedging sales of crude oil production will continue to decline with the suspension of our strategic hedging program, which was launched to provide a degree of financial certainty during a period of rapid growth. With those expansions complete, we are now in a position to finance future growth without the "insurance" of a hedging program.

Growing the Suncor Way

While Suncor's current and future growth projects are geographically widespread and involve different parts of our operations, they share several common elements. First, all capital growth plans – from natural gas development and upgrader expansions to refinery modifications – are closely tied to Suncor's oil sands strategy. For example, investments at our refining operations to remove sulphur from diesel fuel will be expanded to also enable removal of sulphur from oil sands feedstocks, providing further market capacity for Suncor's sour products.

Second, in all of our growth plans, we are implementing innovative ways to reduce capital costs (see below) and mitigate ongoing operating costs and environmental impacts associated with recovering, upgrading and marketing oil sands products. Technology will be key to this goal. For example, we are investigating technologies to reduce energy requirements in our in-situ operations with the goal of reducing both operating costs and greenhouse gas emissions.

As we expand our operations, Suncor is planning capital investment of $2.3 billion to $2.5 billion per year. To keep capital costs under control as we grow, Suncor is following a six-point plan:

- **Building a Suncor organization** to manage growth projects to ensure the best people and best practices are always at work.
- **Taking a staged approach to growth** allows us to control the size of projects and apply what we've learned to future stages.
- **Keeping the parts small** with no project components exceeding $1 billion allows better control of both budgets and schedules.
- **Drawing from all available workforce options** for major expansion projects helps manage demand for skilled trades.
- **Building long-term relationships** with "suppliers of choice" improves our service and supply chain management.
- **Eliminating reworks** by meeting advanced engineering milestones before fabrication or construction begins helps control budgets.

Third, all projects are managed by Suncor's internal engineering, procurement and construction management team. Taking a staged approach to growth with internal project management keeps the expertise and control where it belongs – inside the company. This helps maintain a steady core of expertise as competition for skills grows in the oil sands, while also allowing Suncor to apply what we've learned from past projects to our future stages of expansion.

Fourth, all Suncor growth projects are undertaken with the goal of supporting a company-wide return on capital employed of at least 15% at US$28 benchmark crude oil prices. Since our last major expansion in 2001, Suncor's major project investments have supported our return on capital goals, consistently coming in on budget and on schedule, a track record that is expected to continue in 2005 and beyond.

Finally, growing the Suncor way also means looking at expansion beyond the steel and pipe of our operations. Suncor's vision is to be a sustainable energy company – our goal is to manage our business in a way that enhances social and economic benefits to society, while minimizing the environmental footprint that comes with resource development. Working with our stakeholders to deliver strong results in all three areas provides a solid foundation for growth by helping us earn continued support for our current operations and future plans. By including sustainability in our long-term planning, we aim to manage the risks and build on the rewards of our business – for everyone.

The long-term focus of sustainable development was the driving force behind Suncor's seven-point climate change action plan – a plan we put in place long before Kyoto became a household word. Energy efficiency projects and investment in emissions offsets and renewable energy have helped reduce Suncor's greenhouse gas emissions intensity (emissions per unit of production) by 22% since 1990. Suncor will continue to pursue new technologies to reduce our emissions, such as a carbon capture research project that is investigating the potential of using waste gas streams to improve recovery in mature oil fields.

Our People; Our Energy

Energy for the future is not just a business vision – it's an attitude. As Suncor grows, we rely on employees to bring forward new ideas and innovative strategies and turn them into measurable outcomes and solid results for shareholders. In a highly competitive industry, we strive to be an employer of choice and I am honoured that Suncor is that choice for so many seasoned veterans and bright new entrants to the energy industry.

I would also like to recognize your Board of Directors, who bring to Suncor a breadth and depth of experience matched by few companies in the energy industry. Suncor's Board recognizes that in addition to high returns, shareholders also expect high quality disclosure and high standards of governance. That is why Suncor has voluntarily complied with the reporting, certification and attestation provisions under the United States Sarbanes-Oxley Act, Section 404. While I support the intent of this legislation, I am concerned about the growing costs of compliance with Sarbanes-Oxley. Good governance demands that we provide assurance about the integrity of our reported performance – but it also demands that management constantly ask if costs incurred by the company are delivering a corresponding value to you, our shareholders.

The goal of delivering value to our shareholders will guide Suncor as we enter a new phase of expansion – expansion that will be built on the foundation of good governance, a strong team and a proven strategy. Suncor's employees, management and your Board of Directors thank you for your continued support. Together, we've built a successful past. Together, we'll provide the energy for the future.

Rick George

Rick George
president and chief executive officer

2004: What we promised and what we delivered

Reduce lost-time injury frequencies. Lost time injuries were reduced to 19 in 2004 from 21 in 2003, despite an additional four million person-hours worked.

Increase oil sands production to an average of 225,000 to 230,000 barrels per day (bpd). At 215,600 bpd, upgraded production fell short of target due to unscheduled maintenance. Including in-situ bitumen, oil sands production averaged 226,500 bpd.

Increase natural gas production volumes to 190 to 195 million cubic feet per day (mmcf/d). Natural gas production exceeded targets, averaging 200 mmcf/d, an increase of 7% over 2003

Maintain base oil sands cash operating costs at an annual average of $10.75 to $11.75 per barrel. At $11.95 per barrel, cash operating costs were slightly higher than original targets.

Build for future oil sands growth and advance operations through use of improved technology. Suncor met all construction schedules and cost estimates for growth projects including projects to increase oil sands production capacity to 260,000 bpd by the end of 2005. As planned, Suncor also began construction on the next oil sands upgrader expansion.

Advance downstream integration plans. Modifications to the Sarnia and Denver refineries to meet low-sulphur fuel regulations and integrate increased volumes of oil sands production were launched in mid-2004.

Maintain a strong balance sheet. Suncor maintained relatively steady net debt of $2.2 billion, while redeeming preferred securities and investing $1.8 billion in capital.

Continue to pursue energy efficiencies, greenhouse gas offsets and new renewable energy projects. Land was purchased for a proposed ethanol plant in Ontario while in Magrath, Alberta, Suncor commissioned a 30-megawatt wind power project.

2005: Our targets and how we'll get there

Complete fire recovery and planned maintenance at oil sands to return to full production in the third quarter. While we work to complete maintenance as quickly as possible, the priority is employee and contractor safety. At the time of this report, the impact of the outage on annual production and cash operating costs is not yet known; this information will be provided to shareholders when it is available.

Reduce lost-time injury frequencies. Suncor's comprehensive Journey to Zero safety program will continue to promote awareness, leadership and a safety culture across Suncor's operations.

Increase natural gas production volumes to 205 to 210 mmcf/d. Suncor will continue to focus on high impact natural gas plays as we work to maintain our annual target of 3% to 5% production growth.

Build for future oil sands growth. Expansion projects to increase oil sands production capacity to 260,000 bpd are expected to be complete by the end of 2005. Construction will continue in 2005 to take Suncor to a planned capacity of 350,000 bpd in 2008. Suncor also expects to file a regulatory application for a third upgrader planned to take oil sands production to a target of 500,000 to 550,000 bpd in 2010 to 2012.

Focus on enterprise-wide efficiency. To more seamlessly integrate our operations and prepare for future growth, Suncor is implementing company-wide information and management systems.

Advance downstream integration plans. Suncor expects to reach peak activity on modifications to the Sarnia and Denver refineries to meet low-sulphur fuel regulations and integrate increased volumes of oil sands production in both refineries.

Maintain a strong balance sheet. Tight management of debt will remain a priority as we plan to invest $2.5 billion in our long-term growth strategy this year.

Continue to pursue energy efficiencies, greenhouse gas offsets and new renewable energy projects. Suncor plans to advance research into carbon capture in 2005 and will continue to pursue new renewable energy projects. Construction is expected to begin in 2005 on a plant that will supply ethanol for lower emission blended fuels.

To help ensure flexible and reliable resource supplies to feed growing production, Suncor draws on three sources of bitumen: traditional truck and shovel mining; in-situ recovery; and supplementary third-party supply agreements.

Mining

A fleet of 45 cubic-metre shovels and 360-tonne trucks form the heart of Suncor's mining operations. We expect to expand the reach of those massive shovels with plans to extend the Steepbank mine, located near our upgrading operations. At the same time, we are investigating technologies such as mobile crushers and partial sand removal at the mine face that could increase the cost efficiency of our truck fleet.

In-situ

Suncor's Firebag operation uses steam assisted gravity drainage (SAGD) to heat the underground reservoir, allowing deep bitumen deposits to be pumped to the surface. Firebag stage one began producing in January 2004 and continued to ramp up to 19,000 bpd by the end of the year. A second stage, planned to begin producing bitumen by the end of 2005, is proceeding on schedule and on budget. As we look to future stages of in-situ development, we are investigating new technologies that may reduce energy used for steam, while increasing recovery rates.

Third-Party Agreements

To supplement mine and in-situ development and maintain a reliable supply of bitumen for upgrading, Suncor has entered into third-party bitumen supply agreements. One such significant agreement is expected to deliver approximately 27,000 barrels of bitumen per day to Suncor for processing, beginning in 2008. We will continue to investigate innovative supply arrangements as third-party bitumen production in the Athabasca region continues to expand more quickly than upgrading capacity.

building our foundation

Suncor's future is built on 38 years of experience in developing one of the world's largest petroleum resource basins – Canada's oil sands. As the first company to commercially develop the oil sands, we have assembled a high quality resource base that is estimated to contain the raw materials to produce a potential 11 billion barrels of conventional quality crude oil. So, while declining production from mature basins forces conventional producers to drill deeper and in more remote locations, we can focus on developing the technology and expertise to increase production and build on our position as one of the lowest cost crude oil producers in North America.

Developing our resources includes our human resources. Koreen Peck is an apprentice welder on the Oil Sands team working towards becoming one of our in-house experts.

expanding resources

Proved

Probable

Reserves and Resources

Barrels of oil

Expanding to Half a Million Barrels per Day

The current phase of Suncor's oil sands expansion is expected to take our year-end production capacity from about 225,000 barrels per day (bpd) in 2004 to 260,000 bpd in 2005. At the same time, integration of in-situ bitumen streams into the upgrader, planned for late 2005, is expected to increase the proportion of higher value products in our sales mix. Capital investment totalling an estimated $3.6 billion in additional upgrader expansion and further development of in-situ, mining and extraction operations is planned to boost our production capacity to 350,000 bpd in 2008 – an increase of more than 50% over current capacity. In 2010 to 2012, the addition of a third complete upgrader is expected to drive Suncor's production to a goal of 500,000 to 550,000 bpd.

As Suncor targets major strides in production capacity, we remain focused on the goal of achieving a return on capital employed (ROCE) of at least 15% at mid-cycle oil prices (US$28 West Texas Intermediate) and maintaining a strong balance sheet. Since completing our last major expansion phase in 2001, we have consistently delivered major capital projects on time and on budget, helping to support a ROCE of 19% in 2004.

Providing Energy to the Bottom Line

Suncor's natural gas business produces conventional natural gas in Western Canada. Our natural gas strategy is focused on building competitive operating areas, improving efficiencies, and creating new and low-capital business opportunities. Keeping pace with company-wide natural gas purchases provides a "price hedge" that allows a degree of protection from volatile market prices for natural gas. Suncor is targeting natural gas production growth of 3% to 5% per year, with a 2005 production target of 205 to 210 million cubic feet per day.

manufacturing value

With a large resource base, Suncor doesn't need to look for new oil reservoirs. Instead, we look for new ways to expand and improve our synthetic crude manufacturing process. That's because, while our business is built on the heavy resources of the oil sands, our focus is on producing the higher value crude oil products that are always in demand and less prone to wide swings in commodity price. As we continue to grow, we are investing in new technologies to expand our current twin train upgrading facility with the goal of increasing production and improving operational flexibility.

John Hoffman, part of our Natural Gas and Renewable Energy team, is one of many employees helping to provide energy to the bottom line.

Energy for the future means reaching our long-term goal of producing more than half a million barrels of oil per day.

expanding production

Year-end production capacity (thousands of barrels per day)

2005 and subsequent years represent targets.

Marketing Agreements

From Alberta's north to Ontario, the U.S. Midwest and Rocky Mountain regions, Suncor is connected to more than 70 refining operations through North America's extensive pipeline network. Third-party pipeline expansions are expected to increase our reach while proposed pipes to Canada's west coast could provide access to California and a growing Asian market. By managing contracts, transportation and product specifications, we're working to build stable, long-term markets for our production.

Refining

Suncor's 70,000 barrel per day (bpd) refinery in Sarnia, Ontario, and 60,000 bpd facility in Denver, Colorado take our integration strategy a step further, providing an internal market for our crude oil production. Refined products include gasoline, distillates, asphalt and petrochemicals sold to retail, industrial and commercial customers.

As we expand our oil sands operations, we are also expanding our refining capabilities. In 2004, construction began at our Denver facility on a US$300 million capital upgrade to meet clean fuels regulations and to modify the refinery to handle 10,000 bpd to 15,000 bpd of oil sands sour crude blends. At our Sarnia refinery, we plan to invest $800 million to expand the refinery's capacity and enable it to process approximately 40,000 bpd of oil sands sour crude blends, while also reducing sulphur in diesel fuels.

Retail

Suncor operates retail stations and supplies products to a broader retail network through joint-venture operations and long-term supply contracts.

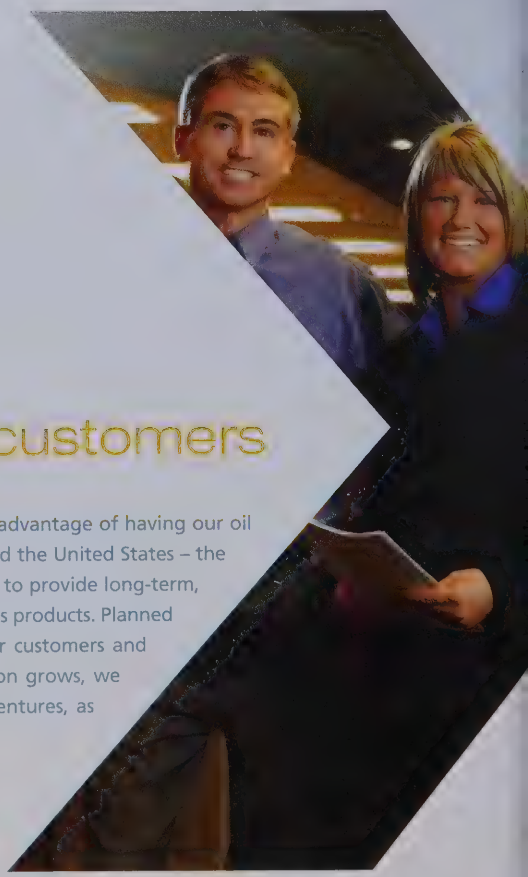
Operating under the Sunoco brand in Ontario and Phillips 66 brand in Colorado, our retail service networks provide an opportunity to capture further value from our refined products. Retail sites in both networks are undergoing renovations and improvements to associated convenience stores to help maintain and build market share in this highly competitive market.

Renewable Energy for New Markets

Suncor continues to invest in projects to supply new markets for renewable energy. In 2004, we launched our second wind power partnership in southern Alberta. In Ontario, construction is expected to begin in 2005 on a plant that will supply ethanol – a renewable energy source for lower emission blended fuels.

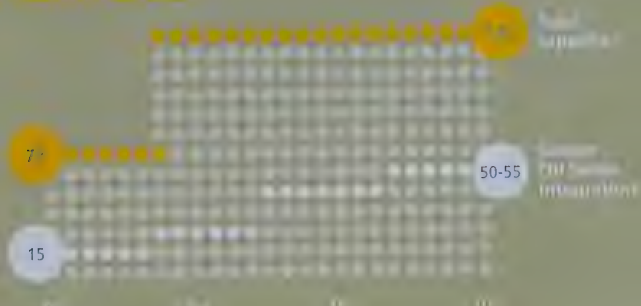
connecting with customers

Suncor's refining and marketing business is built on the competitive advantage of having our oil sands production base securely connected to customers in Canada and the United States – the largest crude oil market in the world. Our downstream strategy aims to provide long-term, stable markets, while also capturing additional value from our oil sands products. Planned oil sands production increases are aligned with the demands of our customers and with modification of our own refining assets. As oil sands production grows, we continue to investigate potential refining asset purchases or joint-ventures, as well as innovative third-party supply contracts.



Jeph Virtue and Celina VanSpankeren, are part of our Major Projects team working on the expansion of the Sarnia and Denver refineries.

expanding markets



management's discussion and analysis

February 23, 2005

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 53 for additional information.

This MD&A should be read in conjunction with Suncor's audited Consolidated Financial Statements and the accompanying notes. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures cash flow from operations, return on capital employed and cash and total operating costs per barrel referred to in this MD&A, are not prescribed by GAAP and are outlined and reconciled in Non GAAP Financial Measures on page 51.

Certain prior years amounts have been reclassified to enable comparison with the current year's presentation.

Base operations refers to Oil Sands mining and upgrading operations.

Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (mcf) of natural gas : one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

References to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries and joint-venture investments, unless the context otherwise requires.

The tables and charts in this document form an integral part of this MD&A.

Additional information about Suncor filed with Canadian securities commissions and the United States Securities and Exchange Commission, including periodic quarterly and annual reports and the Annual Information Form (AIF/Form 40-F), is available on-line at www.sedar.com and www.sec.gov.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, Suncor has provided cost estimates for projects that, in many cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material.

suncor overview and strategic priorities

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. The company operates four business segments:

- **Oil Sands** Suncor's core business unit, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands and upgrades it to refinery feedstock, diesel fuel and byproducts.
- **Natural Gas** (NG) produces natural gas in Western Canada, providing revenues and serving as a price hedge against the company's purchased natural gas consumption.
- **Energy Marketing and Refining – Canada** (EM&R) operates a 70,000 barrel per day (bpd) capacity refinery in Sarnia, Ontario and markets refined petroleum products to customers primarily in Ontario and Quebec, including retail customers in Ontario under the Sunoco brand. (Sunoco in Canada is separate and unrelated to Sunoco in the United States, which is owned by Sunoco, Inc. of Philadelphia.) EM&R also manages Suncor's company-wide energy marketing and trading activities and sales of all Oil Sands and NG production. Financial results relating to the sales of Oil Sands and NG production are reported in those business segments.
- **Refining and Marketing – U.S.A.** (R&M) operates a 60,000 bpd capacity refinery in the Denver, Colorado area as well as related pipeline assets. R&M's retail network of 43 Phillips 66-branded stations operates primarily in the Denver area. In addition, the business has contract agreements with about 140 Phillips 66-branded outlets that operate throughout Colorado.

Suncor's strategic priorities are:

Operational:

- Developing Suncor's oil sands resource base through mining and in-situ technology and supplementing Suncor bitumen production with third-party supply.
- Expanding Oil Sands extraction and upgrading facilities to increase crude oil production.
- Integrating Oil Sands production into the North American energy market through Suncor's refineries and the refineries of other customers to reduce vulnerability to supply and demand imbalances.
- Managing environmental and social performance to earn continued stakeholder support for Suncor's ongoing operations and growth plans.
- Maintaining a strong focus on worker, contractor and community safety as an overriding operational priority.

Financial:

- Controlling costs through a strong focus on operational excellence, economies of scale and improved management of engineering, procurement and construction of major projects.
- Reducing risk associated with natural gas price volatility by producing natural gas volumes that meet or exceed purchases.
- Maintaining a strong balance sheet by controlling debt and closely managing capital cost outlays.
- Targeting opportunities that support a minimum 15% return on capital employed (ROCE) at US$28 West Texas Intermediate (WTI) crude oil prices and a Cdn$/US$ exchange rate of $0.75.

Significant Developments in 2004 and Subsequent Event

- Suncor's common shares closed at $42.40 at the end of 2004, an increase of 30% over 2003. Suncor shares outperformed the S&P 500 Index during the year.
- Total production increased to 263,300 barrels of oil equivalent per day (boe/d), from 251,500 boe/d in 2003.
- Production at Suncor's Oil Sands facility averaged 226,500 bpd, comprising 215,600 bpd from base operations and 10,900 bpd of bitumen from the company's in-situ operations. Production in 2003 averaged 216,600 bpd; there was a 30-day planned maintenance shutdown and no in-situ production that year.
- Cash operating costs from Oil Sands base operations averaged $11.95 per barrel during 2004, at an average natural gas price of US$6.20 per thousand cubic feet.
- Natural gas production increased to 200 million cubic feet per day (mmcf/d) in 2004, compared to 187 mmcf/d in 2003.
- Refining margins averaged 8.0 cents per litre (cpl) for Canadian operations and 6.7 cpl for U.S. operations. This compares to 6.5 cpl for Canadian operations and 5.9 cpl for U.S. operations during 2003. Retail gasoline margins averaged 4.4 cpl for Canadian operations and 5.4 cpl for U.S. operations compared to 6.6 cpl for Canadian operations and 5.6 cpl for U.S. operations the year before.
- During 2004, work to expand Oil Sands production capacity to 260,000 bpd continued on schedule and on budget. Suncor also began preliminary site work and vessel construction for projects planned to increase production capacity to 350,000 bpd in 2008.
- In 2004, expansion and upgrades of the company's Sarnia and Denver refineries were launched.
- While Suncor invested $1.8 billion in capital spending primarily to expand operations, maintaining a strong balance sheet remained a priority. At December 31, 2004, Suncor's net debt (including cash and cash equivalents) was approximately $2.2 billion, compared to $2.1 billion at December 31, 2003. Including preferred securities, net debt at December 31, 2003 was $2.6 billion. These securities were redeemed in 2004.
- Suncor achieved a company-wide return on capital employed of 19.1% (excluding major projects in progress).
- In January 2005, a fire at Oil Sands damaged Upgrader 2. As a result, production at Oil Sands is expected to be reduced until the third quarter (see page 21).

selected financial information

Annual Financial Data

Year ended December 31 ($ millions except per share data)	**2004**	2003	2002
Revenues	**8 621**	6 571	5 032
Net earnings	**1 100**	1 075	749
Total assets	**11 804**	10 501	9 011
Long-term debt	**2 217**	2 448	2 686
Dividends			
Common shares	**103**	87	77
Preferred securities	**9**	45	48
Net earnings attributable to common shareholders per share – basic	**2.40**	2.41	1.61
Net earnings attributable to common shareholders per share – diluted	**2.36**	2.24	1.58
Cash dividends per share	**0.23**	0.19	0.17

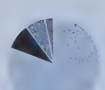
Outstanding Share Data

As at December 31, 2004 (thousands)	
Number of common shares	454 241
Number of common share options	20 687
Number of common share options – exercisable	9 067

Quarterly Financial Data

	2004 Quarter ended				2003 Quarter ended			
($ millions except per share)	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**	Dec. 31	Sept. 30	June 30	Mar. 31
Revenues	**2 310**	**2 315**	**2 201**	**1 795**	1 698	1 788	1 385	1 700
Net earnings	**333**	**337**	**203**	**227**	302	291	116	366
Net earnings attributable to common shareholders per share								
Basic	**0.73**	**0.74**	**0.44**	**0.48**	0.67	0.63	0.27	0.84
Diluted	**0.72**	**0.73**	**0.43**	**0.46**	0.62	0.61	0.24	0.77

Net Earnings(1)
($ millions)



	04	03	02
Oil Sands	**995**	888	782
Natural Gas	**115**	120	34
Energy Marketing and Refining – Canada	**80**	53	61
Refining and Marketing – U.S.A.(3)	**34**	18	—

Cash Flow from Operations(1)
($ millions)

	04	03	02
Oil Sands	**1 752**	1 803	1 475
Natural Gas	**319**	298	164
Energy Marketing and Refining – Canada	**188**	164	112
Refining and Marketing – U.S.A.(3)	**59**	34	—

Capital Employed(1) (2)
($ millions)

	04	03	02
Oil Sands	**4 169**	4 050	4 512
Natural Gas	**448**	400	422
Energy Marketing and Refining – Canada	**512**	551	485
Refining and Marketing – U.S.A.(3)	**232**	270	—

(1) Excludes Corporate and Eliminations segment.
(2) Excludes major projects in progress.
(3) Refining and Marketing – U.S.A. 2003 data reflects five months of operations since acquisition on August 1, 2003.

Quarterly net earnings for 2004 and 2003 fluctuated due to a number of factors:

- U.S. dollar denominated crude oil prices were higher on average in 2004 compared to 2003.
- Oil Sands Alberta Crown royalties increased significantly during 2004 as a result of a modification in the Province of Alberta's royalty classification for Firebag in-situ operations and higher crude oil prices (see page 24).
- The impact of scheduled and unscheduled maintenance at Oil Sands (including in-situ operations) reduced production during 2004. In the second quarter of 2003, there was a planned 30-day maintenance shutdown on Upgrader 1 that reduced production capacity during that period.
- Cash operating costs fluctuated due to the factors impacting Oil Sands production and the price and purchased volume of natural gas used for energy in Oil Sands operations.
- Commodity and refined product prices fluctuated as a result of global and regional supply and demand, as well as seasonal demand variations. In the downstream, seasonal fluctuations were reflected in higher demand for vehicle fuels and asphalt in summer and heating fuels in winter.
- Realized commodity prices were unfavourably impacted in 2004 and 2003 by increases in the Canadian dollar compared to the U.S. dollar, which reduced the Canadian dollar revenue earned. The stronger Canadian dollar also resulted in net foreign exchange gains on U.S. dollar denominated debt in 2004 and 2003. These gains were higher in 2003 due to the greater appreciation of the Canadian dollar during 2003 compared to 2004.
- A 1% reduction in the Province of Alberta's corporate tax rates in the first quarter of 2004 increased 2004 net earnings by $53 million. In 2003, changes to federal taxation policies relating to the resource sector and changes to both the Alberta and Ontario provincial tax rates reduced 2003 net earnings by $89 million.

Consolidated Financial Analysis

This analysis provides an overview of Suncor's consolidated financial results for 2004 compared to 2003. For a detailed analysis, see the various business segment analyses.

Net Earnings

Suncor's net earnings were $1.1 billion in 2004, compared with $1.075 billion in 2003 (2002 – $749 million). The increase was primarily due to higher U.S. dollar benchmark crude oil prices (net of widening light/heavy crude oil differentials), increased production, and non-cash reductions in income tax expense due to year-over-year changes in tax rates and resource allowance deductions. These positive impacts were largely offset by higher Oil Sands Alberta Crown royalties, higher crude oil hedging losses and the impact of a stronger Canadian dollar.

Net Earnings Components (1)

Year ended December 31 ($ millions, after tax)	**2004**	2003	2002
Net earnings before the following items:	**1 248**	1 048	718
Firebag in-situ start-up costs	**(14)**	—	—
Oil Sands Alberta Crown royalties	**(261)**	(21)	(22)
Impact of income tax rate reductions on opening net future income tax liabilities	**53**	(89)	10
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**74**	137	8
Sale of retail natural gas marketing business	**—**	—	35
Net earnings as reported	**1 100**	1 075	749
Net earnings attributable to common shareholders as reported	**1 088**	1 085	722

(1) This table explains some of the factors impacting Suncor's after-tax net earnings. For comparability purposes, readers should rely on the reported net earnings that are prepared and presented in the company's consolidated financial statements and notes in accordance with Canadian GAAP.

Industry Indicators

(Average for the year unless otherwise noted)	**2004**	2003	2002
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**41.40**	31.05	26.10
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**52.55**	43.55	40.75
Light/heavy crude oil differential US$/barrel WTI at Cushing less Bow River at Hardisty	**12.80**	8.00	5.95
Light/heavy crude oil differential US$/barrel WTI at Cushing less Lloyd Light Blend at Hardisty	**13.55**	8.65	6.55
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**6.20**	5.45	3.25
Natural gas (Alberta spot) Cdn$/mcf at AECO	**6.80**	6.70	4.05
New York Harbour 3-2-1 crack US$/barrel (1)	**6.90**	5.30	3.35
Refined product demand (Ontario) percentage change over prior year (2)	**4.3**	2.5	0.6
Exchange rate: Cdn$/US$	**0.77**	0.72	0.64

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking two times the New York Harbour gasoline margin plus one times the New York Harbour distillate margin and dividing by three.

(2) Figures for 2002 and 2003 are based on published government data. Figures for 2004 are internal estimates based on preliminary government data.

Revenues were $8.6 billion in 2004, compared with $6.6 billion in 2003 (2002 – $5.0 billion). The increase resulted primarily from the following:

- Average commodity prices were higher in 2004 than in 2003. A 33% increase in average U.S. dollar WTI benchmark pricing increased the selling price of Oil Sands crude oil production. Mitigating this increase, average light/heavy crude oil differentials compared to the WTI benchmark index widened approximately 60%. As a result, the net price Suncor received on certain sour crude oil and bitumen sales did not increase by as much as the increase in WTI.
- In 2004, Oil Sands sales averaged 226,300 bpd, compared with 218,300 bpd in 2003 (2002 – 205,300 bpd). Increased crude oil production drove higher sales volumes. Oil Sands sales in 2004 included production of 10,900 bpd of bitumen from Firebag in-situ operations, which commenced operations during the year. Overall sales volumes in 2004 were lower than anticipated due to the effects of unplanned maintenance at both the base plant and in-situ operations. In 2003, sales volumes were negatively impacted by a planned 30-day maintenance shutdown.
- Refined product wholesale and retail prices in both EM&R and R&M were higher due to higher crude oil feedstock prices. In addition, a 3% increase in refined product sales volumes in EM&R had a positive impact on revenue.
- R&M revenues increased as a result of one full year of operations, compared to five months in 2003 (R&M was acquired on August 1, 2003).

Partially offsetting these increases were the following:

- A 7% increase in the average Cdn$/US$ exchange rate resulted in lower realizations on Suncor's crude oil sales basket and natural gas sales. Because crude oil and natural gas are primarily sold based on U.S. dollar benchmark prices, a narrowing of the exchange rate difference reduced the Canadian dollar value of Suncor's products.
- Higher strategic crude oil hedging losses decreased revenues. During 2004, Suncor sold a portion of its crude oil production at fixed prices that were lower than prevailing market prices. After-tax hedging losses in 2004 were $397 million compared to $155 million in 2003.

Overall, higher prices, net of the impact of the higher Cdn$/US$ exchange rate, increased total revenues by approximately $1.2 billion. Higher volumes increased revenues by approximately $220 million and the impact of 12 months of R&M results compared to five months in 2003 increased revenues by approximately $980 million. These impacts were partially offset by hedging losses, which reduced revenues by approximately $380 million.

Purchases of crude oil and crude oil products were $2.9 billion in 2004 compared with $1.7 billion in 2003 (2002 – $1.2 billion). The increase was primarily due to the following:

- Higher benchmark crude oil feedstock prices, which increased purchases by approximately $360 million.
- Higher feedstock requirements as a result of one full year of operations for R&M, compared to five months in 2003, increased purchases by approximately $830 million.

- The repurchase of crude oil originally sold to a Variable Interest Entity (VIE) in 1999 increased purchases at Oil Sands in the second quarter by approximately $55 million.
- The 3% increase in refined product sales in EM&R required the purchase of higher volumes of feedstock and refined products.

Operating, selling and general expenses were $1.8 billion in 2004 compared with $1.5 billion in 2003 (2002 – $1.3 billion). The primary reasons for the increase were:

- The effects of 12 months of operations at R&M in 2004 compared to only five months of operations in 2003.
- The first year of in-situ operations.
- Higher operating expenses, including higher energy costs in all businesses.
- Increased maintenance activities due to scheduled maintenance at the R&M Denver refinery and the EM&R Sarnia refinery as well as unscheduled maintenance at Oil Sands base plant and in-situ operations, and the EM&R Sarnia refinery.
- Corporate costs related to the company's enterprise resource planning (ERP) implementation project as well as costs related to obtaining certification under the Sarbanes-Oxley Act, Section 404.
- Higher stock-based compensation expense, primarily due to the achievement of certain performance based vesting conditions under the company's SunShare stock option plan and an increase in the overall number of stock options being expensed.

Transportation and other expenses remained relatively constant at $132 million in 2004 compared to $135 million in 2003 (2002 – $128 million). Increased transportation costs of $13 million in R&M due to a full year of operations, were offset by mark-to-market gains on inventory-related derivatives in Oil Sands. Consistent with 2003, Oil Sands pipeline tolls continued to be reduced by initial shipper toll adjustments. Oil Sands initial shipper toll adjustments are currently expected to continue until at least 2007.

Depreciation, depletion and amortization (DD&A) was $717 million in 2004 compared with $618 million in 2003 (2002 – $595 million). DD&A at Oil Sands increased by $45 million due to higher overburden amortization, higher maintenance shutdown and catalyst amortization, and depletion incurred in in-situ operations, which commenced in 2004. NG depletion increased by $24 million, reflecting higher production levels and a higher depletion base. Higher depreciation and amortization of $16 million associated with 12 months of operations in R&M also contributed to the increase.

Exploration expenses were $55 million in 2004, largely unchanged from $51 million in 2003 (2002 – $26 million). Decreased NG dry hole expenses of $11 million in 2004 were offset by higher seismic expenses in NG and higher core hole drilling activity in Oil Sands.

Royalty expenses were $531 million in 2004 compared with $139 million in 2003 (2002 – $98 million). The significant increase in 2004 was primarily related to increased Alberta Crown royalties at Oil Sands. For a further discussion about Oil Sands Crown royalties, see page 24. Royalties in NG also increased by $18 million due to higher realized natural gas prices and higher production volumes.

Taxes other than income taxes were $496 million in 2004 compared to $426 million in 2003 (2002 – $374 million). The increase was primarily due to additional excise taxes related to R&M operations.

Financing expenses were $9 million in 2004 compared with income of $66 million in 2003 (2002 – expense of $124 million). The increase in expenses was primarily due to $77 million of lower foreign exchange gains on the company's U.S. dollar denominated long-term debt. Interest expense net of capitalized interest was $87 million in 2004, compared to $83 million in 2003. The relatively unchanged interest expense net of capitalized interest was a result of reasonably stable levels of long-term debt, effective interest rates and average balances of major projects in progress.

Income tax expense was $536 million in 2004 (33% effective tax rate), compared with $726 million in 2003 (40% effective tax rate) (2002 – $378 million – 33% effective tax rate). Income tax expense in both 2004 and 2003 included the effects of adjustments to opening future income tax balances due to changes in tax rates that reduced tax expense by $53 million in 2004 and increased tax expense by $89 million in 2003. Excluding these adjustments, income tax expense in 2004 was $589 million (36% effective tax rate) compared to $637 million in 2003 (35% effective tax rate). The higher effective rate in 2004 was primarily due to the tax effect of lower foreign exchange gains on long-term debt in 2004 compared to 2003.

Corporate Expenses

After-tax corporate expenses were $124 million in 2004 compared to $4 million in 2003 (2002 – $128 million). The increase was due to higher financing costs and higher operating, selling and general expenses (discussed above).

The corporate office had a net cash deficiency of $334 million in 2004, compared with $235 million in 2003 (2002 – $225 million). The increased deficiency was primarily due to the same factors that increased operating, selling and general expenses, as well as changes in working capital.

Consolidated Cash Flow from Operations

Cash flow from operations was $2.02 billion in 2004 compared to $2.08 billion in 2003 (2002 – $1.44 billion). Excluding the impacts of foreign exchange gains and non-cash future income tax expense, cash flow was primarily impacted by the same factors affecting net earnings. In addition, higher cash overburden spending in 2004 reduced cash flow from operations by $47 million compared to 2003.

Dividends

In the second quarter of 2004, Suncor's Board of Directors approved an increase in the quarterly dividend to $0.06 per share, from $0.05 per share. Total dividends paid during 2004 were $0.23 per share, compared with $0.1925 per share in 2003. The Board periodically reviews the dividend policy, taking into consideration Suncor's capital spending profile, financial position, financing requirements, cash flow and other relevant factors.

Subsequent Event

On January 4, 2005, a fire at Oil Sands damaged Upgrader 2. As a result, production at Oil Sands base operations was reduced to about 110,000 bpd. Repairs are expected to take several months and Suncor does not expect to return to full capacity of 225,000 bpd until the third quarter of 2005.

The company carries property loss and business interruption insurance policies with a combined coverage limit of up to US$1.15 billion, net of deductible amounts, that will mitigate, upon receipt of these funds, a portion of the financial impact of this incident. The primary property loss policy of US$250 million has a deductible per incident of US$10 million and the primary business interruption policy of US$200 million has a deductible per incident of the greater of US$50 million gross earnings lost (as defined in the insurance policy) or 30 days from the incident. In addition to these primary coverage insurance policies, Suncor has excess coverage of US$700 million that can be used for either property loss or business interruption coverage. For business interruption purposes, this excess coverage begins on the later of full utilization of the primary business interruption coverage or 90 days from the date of the incident. For accounting purposes, the company will accrue insurance proceeds up to the net book value of the damaged assets. Proceeds in excess of this amount, as well as business interruption proceeds, will be recorded when unconditionally settled.

As the company is still evaluating the effect of the fire on its operations, the financial impact of this incident cannot currently be determined.

The impact on liquidity and capital resources is described in more detail below.

Liquidity and Capital Resources

Suncor's capital resources at December 31, 2004 consisted primarily of cash flow from operations and available lines of credit. Suncor's level of earnings and cash flow from operations depend on many factors, including commodity prices, production levels, downstream margins related to the operations of EM&R and R&M and Cdn$/US$ exchange rates. In 2005, cash flow from operations will be negatively impacted by the upgrader fire in Oil Sands.

At December 31, 2004, Suncor's net debt (short and long-term debt less cash and cash equivalents) was approximately $2.2 billion compared to $2.1 billion at December 31, 2003. Including preferred securities, net debt was $2.6 billion at December 31, 2003. In February 2004, Suncor repaid all $125 million of its then outstanding 7.4% debentures. In March 2004, the company redeemed its 9.05% and 9.125% preferred securities for cash consideration of $493 million. Approximately $300 million of the reduction in total net debt, including preferred securities in 2004, was generated from cash flow with the balance attributable to foreign exchange gains.

In 2004, Suncor renewed its available credit facilities of approximately $1.7 billion. Suncor's undrawn lines of credit at December 31, 2004, were approximately $1.5 billion. Suncor's current long-term senior debt ratings are A- by Standard & Poor's, A(low) by Dominion Bond Rating Service and A3 by Moody's Investors Service. All debt ratings have a stable outlook.

In 2000, Suncor entered into a financing arrangement with a third-party, whereby Suncor sold an undivided interest in Oil Sands energy services assets for $101 million and leased the assets back from the third-party. Suncor repurchased the assets in December 2004 with financing through existing revolving credit facilities. Since this lease was capitalized for accounting purposes, it was included in Suncor's debt at the end of 2003.

Interest expense on debt continues to be influenced by the composition of the company's debt portfolio, with Suncor benefiting from short-term floating interest rates

continuing at low levels. To manage fixed versus floating rate exposure, Suncor has entered into interest rate swaps with investment grade counterparties, resulting in the swapping of $600 million of fixed rate debt to variable rate borrowings.

Management of debt levels continues to be a priority given Suncor's growth plans. The company believes a phased approach to existing and future growth projects should maintain its ability to manage project costs and debt levels.

Suncor believes it has the capital resources to fund its 2005 capital spending program of $2.5 billion and to meet current working capital requirements, notwithstanding the impact of the fire at Oil Sands on cash flow from operations and the cost to repair damaged facilities. However, the time required for Suncor's Oil Sands facilities to return to full production, and the timing of receipts of the insurance proceeds may significantly impact Suncor's capital resources and consequently Suncor's financing plan will be reviewed throughout 2005. If additional capital is required, the company believes adequate additional financing is available at commercial terms and rates.

Suncor anticipates its growth plan to be largely financed from internal cash flow, which is dependent on commodity prices and other factors. After 2005, to support its growth strategy and sustain operations, Suncor is projecting an annual capital spending program of approximately $2.3 billion to $2.5 billion that will continue for the foreseeable future. Actual spending is subject to change due to such factors as internal and external approvals and capital availability. Refer to the discussion under Risk/Success Factors Affecting Performance on page 25 for additional factors that can have an impact on Suncor's ability to generate funds to support investing activities.

Aggregate Contractual Obligations and Off-balance Sheet Financing

		Payments Due by Period			
($ millions)	Total	2005	2006-07	2008-09	Later Years
Fixed-term debt, commercial paper and capital leases (1)	2 217	91	405	3	1 718
Interest payments on fixed-term debt, commercial paper and capital leases (1)	2 544	141	264	229	1 910
Employee future benefits (2)	441	31	70	80	260
Asset retirement obligations (3)	1 079	47	87	57	888
Non-cancellable capital spending commitments (4)	157	157	—	—	—
Operating lease agreements, pipeline capacity and energy services commitments (5)	4 798	222	438	458	3 680
Total	**11 236**	**689**	**1 264**	**827**	**8 456**

In addition to the enforceable and legally binding obligations quantified in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists and which are expected to be re-sold shortly after purchase, are one example of excluded items.

(1) Includes $2,104 million of U.S. and Canadian dollar denominated debt that is redeemable at the option of the company. Maturities range from 2007 to 2034. Interest rates vary from 5.95% to 7.15%. The company entered into various interest rate swap transactions maturing in 2007 and 2011 that resulted in an average effective interest rate in 2004 ranging from 3.5% to 4.3% on $600 million of the company's medium-term notes. Approximately $89 million of commercial paper with an effective interest rate of 2.3% was issued in 2004.

(2) Represents the undiscounted expected benefit payments to retirees for pension and other post-employment benefits.

(3) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.

(4) Non-cancellable capital commitments related to capital projects totalled approximately $157 million at the end of 2004. The grouping of commitments outstanding is associated with the Firebag in-situ development ($48 million), expanded production facilities at Oil Sands ($27 million), and desulphurization projects at the company's refineries ($82 million).

(5) Includes transportation service agreements for pipeline capacity and tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta, as well as energy services agreements to obtain a portion of the power and steam generated by a cogeneration facility owned by a major energy company. Non-cancellable operating leases are for service stations, office space and other property and equipment.

The company is subject to financial and operating covenants related to its public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as described in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations.

In addition, a very limited number of the company's commodity purchase agreements, off-balance sheet arrangements and derivative financial instrument agreements, contain provisions linked to debt ratings that may result in settlement of the outstanding transactions should the company's debt ratings fall below investment grade status.

At December 31, 2004, the company was in compliance with all material covenants and its debt ratings were investment grade with a stable outlook. For more information, see page 21.

Variable Interest Entities and Guarantees

At December 31, 2004, the company had off-balance sheet arrangements with Variable Interest Entities (VIEs), and indemnification agreements with other third parties, as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less, to a third-party. The third-party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2004, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses for certain counterparties, which did not exceed $50 million in 2004. A liability has not been recorded for this indemnification as the company believes it has no significant exposure to credit losses. There were no new securitization proceeds in 2004. Proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2004, were approximately $2,073 million. The company recorded an after-tax loss of approximately $2 million on the securitization program in 2004 (2003 and 2002 – $3 million).

In 1999, the company entered into an equipment sale and leaseback arrangement with a third-party for proceeds of $30 million. The third-party's sole asset is the equipment sold to it and leased back by the company. The initial lease term covers a period of seven years and as at December 31, 2004, was accounted for as an operating lease. The company has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. An early termination purchase option allows for the repurchase of the equipment at a specified date in 2005. Had the company elected to terminate the lease at December 31, 2004, the total cost would have been $25 million. Annualized equipment lease payments in 2004 were $6 million (2003 – $4 million; 2002 – $2 million). This VIE was consolidated effective January 1, 2005.

The company has agreed to indemnify holders of the 7.15% fixed-term U.S. dollar notes, the 5.95% fixed-term U.S. dollar notes and the company's credit facility lenders for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, and certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

Outlook

During 2005, management will focus on the following operational priorities:

- Complete fire recovery and planned maintenance at Oil Sands to return to full production in the third quarter.
- Increase natural gas production volumes to 205 to 210 mmcf/d. Suncor will continue to focus on high impact natural gas plays and work to achieve an annual target of 3% to 5% production growth. For more information, see page 43.
- Build for future Oil Sands growth. Expansion projects to increase Oil Sands production capacity to 260,000 bpd are expected to be complete by the end of 2005. Work to bring production capacity to 350,000 bpd in 2008 is also expected to reach several milestones with fabrication and transport of major vessels planned to be completed in 2005. In planning for expansion beyond 2008, Suncor expects to file a regulatory application in 2005 to construct a third upgrader, a key step towards increasing production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. For more information, see page 39.

* Focus on enterprise-wide efficiency. To more seamlessly integrate Suncor's operations and prepare for future growth, the company is implementing a company-wide ERP information and management system.
* Advance downstream integration plans. Suncor will reach peak activity on modifications to the Sarnia and Denver refineries to meet 2006 low-sulphur diesel regulations and integrate increased volumes of oil sands production in both refineries. For more information, see pages 47 and 50.

Oil Sands Crown Royalties and Cash Income Taxes

Crown royalties in effect for Oil Sands operations require payments to the Government of Alberta, based on gross revenues less related transportation costs (R), less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R. In April 2004, the Alberta government confirmed it would modify Suncor's royalty treatment because it does not recognize the company's Firebag in-situ facility as an expansion to the company's existing Oil Sands Project. Accordingly, for Alberta Crown royalty purposes, Suncor's oil sands operations are considered two separate projects: base oil sands mining and associated upgrading operations with royalties based on upgraded product values and the current Firebag in-situ project with royalties based on bitumen values. On this basis, Suncor has provided for estimated pretax Alberta Oil Sands Crown royalties in 2004 of $407 million. Alberta Oil Sands Crown royalties may be subject to change as policies arising from the Government's position are finalized and audits of the 2004 and prior years are completed. Changes to the estimated amounts previously recorded will be reflected in the company's financial statements on a prospective basis and may be significant.

In July, Suncor issued a statement of claim against the Crown, seeking, among other things, to overturn the government's decision on the royalty treatment of Firebag. The Crown has issued a statement of defence. To date, there have been no significant further developments with respect to these legal proceedings.

Alberta Crown royalties payable in 2005 and subsequent years continue to be highly sensitive to, among other factors, changes in crude oil and natural gas pricing, foreign exchange rates, and total capital and operating costs for each Project. In addition, 2004 was a transition year for Oil Sands as the remaining amount of prior years' allowable costs carried forward of approximately $600 million were claimed in 2004 to reduce the company's 2004 Alberta Crown royalty obligation. No such carryforward of allowed costs exists for 2005 and subsequent years.

Assuming anticipated levels of operating expenses and capital expenditures for each Project remain relatively constant, variability in expected Oil Sands royalty expense is primarily a function of changes in expected annual Oil Sands revenue. Absent the impact of the January 4th, 2005 fire, the company expected that Alberta Oil Sands Crown royalty expense for the period 2005 to 2007 would range from approximately 12% to 14% of total Oil Sands Revenue based on WTI prices of US$40 to US$50 respectively. For subsequent years, this percentage range may decline as anticipated new in-situ production attracts royalties based on bitumen values. This royalty percentage range is based on the following assumptions: a natural gas price of US$6.25 per mcf at Henry Hub; a light/heavy oil differential to the U.S. Gulf Coast of US$9 per barrel; and a Cdn$/US$ exchange rate of 0.80.

Alberta Oil Sands Crown royalty expense in 2005 and 2006 may be significantly impacted by the amount and timing of the recognition of the business interruption insurance proceeds. Accordingly, the range of annualized royalty expense as a percentage of revenues, may differ from that stated above, and these differences may be material.

Based on the company's current long-term planning assumptions, the 25% R-C royalty would continue to apply to the existing Oil Sands base operations in future years and the 1% minimum royalty would apply to the Firebag project until the next decade. The company continues to discuss the terms of Suncor's option to transition to the generic bitumen-based royalty regime in 2009. After 2009 the royalty would be based on bitumen value if Suncor exercised its option to transition to the Province of Alberta's generic regime for oil sands royalties. In the event that Suncor exercises this option, future upgrading operations would not be included for Oil Sands royalty purposes.

The timing of when the Oil Sands operation will be fully cash taxable is highly dependent on crude oil commodity prices and capital invested. At prices between US$34 and US$50 per barrel WTI, an average annual Cdn$/US$ foreign exchange rate of $0.80, future investment plans and certain other assumptions, Suncor does not believe it will be fully cash taxable until the next decade. However, in any particular year, the company's Oil Sands and NG operations may be subject to some cash income tax due to the sensitivity to crude oil and natural gas commodity price volatility and the timing of recognition of capital expenditures for tax purposes. Based on the assumptions stated above, the company anticipates that Oil Sands and NG operations will be partially cash taxable commencing in 2009 at US$34 per barrel WTI, and in 2007 at US$40 to US$50 per barrel WTI, until the next decade, at which point it is expected to become fully cash taxable.

The information in the preceeding paragraphs under Oil Sands Crown Royalties and Cash Income Taxes incorporates operating and capital cost assumptions included in the company's current budget and long-range plan, and is not an estimate, forecast or prediction of actual future events or circumstances.

Climate Change

Suncor's effort to reduce greenhouse gas emissions is reflected in its pursuit of greater internal energy efficiency, investment in emissions offsets and carbon capture research and development.

Suncor continues to consult with governments about the impact of the Kyoto Protocol and plans to continue to actively manage its greenhouse gas emissions. The company currently estimates that in 2010 the impact of the Kyoto Protocol on Oil Sands cash operating costs would be an increase of about $0.20 to $0.27 per barrel. This estimate assumes a reduction obligation of 15% from 2010 business-as-usual energy intensity[(1)] and that the maximum price for carbon credits would, as the Government of Canada indicated in 2002, be capped at $15 per tonne of carbon dioxide equivalent until 2012. Based on these assumptions, Suncor does not currently anticipate that the cost implications of federal and provincial climate change plans will have a material impact on its business or future growth plans.

The ultimate impact of Canada's implementation of the Kyoto Protocol, however, remains subject to numerous risks, uncertainties and unknowns. These include the outcome of discussions between the federal and provincial governments, the form, impact and effectiveness of implementing legislation, the ultimate allocation of reduction obligations among economic sectors, and other details of Canada's implementation plan, as well as international developments. In addition, the Government of Canada has not yet indicated what, if any, limitations will be placed on the price of carbon credits after 2012. It is not possible to predict how these and other Kyoto-related issues will ultimately be resolved.

Risk/Success Factors Affecting Performance

Suncor's financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and exchange rates, environmental regulations, stakeholder support for growth plans, extreme winter weather, regional labour issues and other issues discussed within Risk/Success Factors for each Suncor business segment. A more detailed discussion of risk factors is presented in the company's most recent AIF/40-F, filed with securities regulatory authorities.

Commodity Prices, Refined Product Margins and Exchange Rates

Suncor's future financial performance remains closely linked to hydrocarbon commodity prices, which can be influenced by many factors including global and regional supply and demand, seasonality, worldwide political events and weather. These factors, among others, can result in a high degree of price volatility. For example, from 2002 to 2004 the monthly average price for benchmark WTI crude oil ranged from a low of US$19.70 per barrel to a high of US$53.10 per barrel. During the same three-year period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$2.00 per mcf to a high of US$9.30 per mcf. Suncor believes commodity price volatility will continue.

Crude oil and natural gas prices are based on U.S. dollar benchmarks that result in Suncor's realized prices being influenced by the Cdn$/US$ currency exchange rate, thereby creating an element of uncertainty for the company. Should the Canadian dollar strengthen compared to the U.S. dollar, the negative effect on net earnings would be partially offset by foreign exchange gains on the company's U.S. dollar denominated debt. Conversely, should the Canadian dollar weaken compared to the U.S. dollar, the positive effect on net earnings would be partially offset by foreign exchange losses on the company's U.S. dollar denominated debt. Cash flow from operations is not impacted by the effects of currency fluctuations on the company's U.S. dollar denominated debt.

Changes to the Cdn$/US$ exchange rate relationship can create significant volatility in foreign exchange gains or losses. On the outstanding US$1 billion in U.S. dollar denominated debt at the end of 2004, a $0.01 change in the Cdn$/US$ exchange rate would change earnings by approximately $12 million after tax.

During 2004, the strengthening of the Canadian dollar against the U.S. dollar resulted in a $74 million after tax foreign exchange gain on the company's U.S. dollar denominated debt.

Suncor's U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for these projects.

(1) Reflects the level of greenhouse gas emissions that would have occurred in the absence of energy efficiency and process improvements after 2000.

Sensitivity Analysis [1]

	2004 Average	Change	Approximate Change in Cash Flow from Operations	Approximate Change in After-tax Earnings
Oil Sands				
Price of crude oil ($/barrel) [2]	$42.28	US$1.00	43	28
Sweet/sour differential ($/barrel)	$8.65	US$1.00	32	20
Sales (bpd)	226 300	1 000	10	7
Natural Gas				
Price of natural gas ($/mcf) [2]	$6.70	0.10	6	3
Production of natural gas (mmcf/d)	200	10	16	7
Energy Marketing and Refining – Canada				
Retail gasoline margins (cpl)	4.4	0.1	2	1
Refining/wholesale margin (cpl) [2]	8.0	0.1	6	4
Refining and Marketing – U.S.A.				
Retail gasoline margins (cpl)	5.4	0.1	—	—
Refining/wholesale margin (cpl)	6.7	0.1	3	2
Consolidated				
Exchange rate: Cdn$/US$	0.77	0.01	33	10

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and after-tax earnings based on actual 2004 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2004 results. A change in any one factor could compound or offset other factors.

(2) Includes the impact of hedging activities.

Derivative Financial Instruments

The company periodically enters into commodity-based derivative financial instruments such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to variations in underlying commodity indices. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage exposure to interest rate fluctuations.

The company also uses energy derivatives, including physical and financial swaps, forwards and options to gain market information and to earn trading revenues. These trading activities are accounted for at fair value in the company's consolidated financial statements.

Derivative contracts accounted for as hedges are not recognized in the Consolidated Balance Sheets. Realized and unrealized gains or losses on these contracts, including realized gains and losses on derivative hedging contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized.

Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Commodity Hedging Activities Suncor's strategic crude oil hedging program has been the subject of periodic management reviews to determine the continued need for hedging in light of the company's tolerance for exposure to market volatility, as well as its need for stable cash flow to finance future growth. In the first quarter of 2004, Suncor's Board of Directors suspended the company's strategic crude oil hedging program. As a result, the company did not enter into any new strategic crude oil arrangements in 2004. The strength of the company's financial position, combined with stable operating costs and a growing production base, reduces the company's risk to crude oil price volatility. Suncor intends to settle all of the strategic crude oil hedges that were outstanding at December 31, 2004, as the related financial derivatives mature throughout 2005.

Prior to the suspension of the hedging program, the company had entered contracts to fix the price on 36,000 barrels of crude oil per day at an average price of US$23 per barrel. These contracts expire on December 31, 2005. On settlement, these contracts result in cash receipts to the company, or payments by the company, for the difference between the derivative contract and market rates for the applicable volumes hedged during the contract term. Such cash receipts or

payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions in the Consolidated Statements of Earnings. In 2004, crude oil hedging decreased Suncor's net earnings by $397 million compared to a decrease of $155 million in 2003 (2002 – decrease of $160 million).

Crude oil hedge contracts outstanding at December 31, 2004, were as follows:

	Quantity (bpd)	Average Price [(a)]	Revenue Hedged ($ millions)	Hedge Period
Crude oil swaps	36 000	23	364 [(b)]	2005

(a) Average price of crude oil swaps is US$/barrel WTI at Cushing.
(b) The revenue hedged is translated to Cdn$ at the year-end exchange rate for convenience purposes.

Financial Hedging Activities Suncor periodically enters into interest rate swap contracts as part of its strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense.

The company has entered into various interest rate swap transactions at December 31, 2004. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of swap transaction	Principal Swapped ($ millions)	Swap Maturity	2004 Effective Interest Rate
Swap of 6.10% Medium Term Notes to floating rates	150	2007	3.6%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.3%
Swap of 6.70% Medium Term Notes to floating rates	200	2011	3.5%

In 2004, these interest rate swap transactions reduced pretax financing expense by $17 million compared to a pretax reduction of $12 million in 2003 (2002 – $13 million).

Fair Value of Strategic Derivative Hedging Instruments The fair value of derivative hedging instruments is the estimated amount, based on broker quotes and internal valuation models that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ millions)	**2004**	2003
Revenue hedge swaps and collars	**(305)**	(285)
Margin hedge swaps	**5**	2
Interest rate swaps	**36**	32
	(264)	(251)

The company also uses derivative instruments to hedge risks specific to individual transactions. The estimated fair value of these instruments was $9 million at December 31, 2004, compared to $1 million at December 31, 2003.

Energy Trading Activities Energy trading activities focus on the commodities the company produces. In addition to those financial derivatives used for hedging activities, the company also uses energy derivatives to gain market information and earn trading revenues. These energy trading activities are accounted for using the mark-to-market method, and as such, physical and financial energy contracts are recorded at fair value at each balance sheet date. During 2004, Suncor recorded a net pretax gain of $11 million compared to a pretax loss of $3 million in 2003 (2002 – nil) related to the settlement and revaluation of financial energy trading contracts. In 2004, the settlement of physical trading activities also resulted in a net pretax gain of $12 million compared to a pretax gain of $2 million in 2003 (2002 – $6 million). These gains were included as energy trading and marketing activities in the Consolidated Statements of Earnings. Net of related general and administrative costs, these activities resulted in 2004 net earnings of $12 million after tax compared to a net loss of $2 million after tax in 2003.

The fair value of unsettled financial energy trading assets and liabilities at December 31 were as follows:

($ millions)	**2004**	2003
Energy trading assets	**26**	5
Energy trading liabilities	**9**	5

The valuation of the above contracts was based on actively quoted prices and internal valuation models.

Counterparty Credit Risk The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date. The company minimizes this risk by entering into agreements with counterparties of which substantially all are investment grade. Risk is also minimized through regular management review of potential exposure to, and credit ratings of, such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	**2004**	2003
Derivative contracts not accounted for as hedges	**7**	30
Unrecognized derivative contracts	**21**	27
	28	57

Environmental Regulations

Environmental laws affect nearly all aspects of Suncor's operations, imposing certain standards and controls on activities relating to oil and gas mining and conventional exploration, development and production. Environmental laws also affect refining, distribution and marketing of petroleum products and petrochemicals and require companies engaged in those activities to obtain necessary permits to operate. Environmental assessments and approvals are required before initiating most new projects or undertaking significant changes to existing operations.

In addition to these specifically known requirements, Suncor expects that changes to environmental laws could impose further requirements on companies operating in the energy industry. Some of the issues include the possible cumulative impacts of oil sands development in the Athabasca region; the need to reduce or stabilize various emissions; issues relating to global climate change, including the uncertainties and risks associated with Canada's implementation of the Kyoto Protocol, and uncertainties associated with predicting emission intensity levels from Suncor's future production; and other potential impacts of government regulation in areas such as land reclamation and restoration, water quality and usage, and reformulated fuels to support lower vehicle emissions. Changes in environmental laws could have an adverse effect on Suncor in terms of product demand, product formulation and quality, methods of production, and distribution and operating costs. The complexity of these issues makes it difficult to predict their future impact on the company.

Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations.

Regulatory Approvals

Before proceeding with most major projects, Suncor must obtain regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow.

Critical Accounting Estimates

Suncor's critical accounting estimates are defined as estimates that are important to the portrayal of the company's financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. Underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances. These assumptions are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Suncor's operating environment changes. Critical accounting estimates are reviewed by the Audit Committee of the Board of Directors annually. The company believes the following are the most critical accounting estimates used in the preparation of its consolidated financial statements.

Property, Plant and Equipment

Suncor accounts for its Oil Sands in-situ and NG exploration and production activities using the "successful efforts" method. This policy was selected over the alternative full-cost method because Suncor believes it provides a more timely accounting of the success or failure of exploration and production activities.

The application of the successful efforts method of accounting requires Suncor's management to determine the proper classification of activities designated as developmental or exploratory, which ultimately determines the appropriate accounting treatment of the costs incurred. The results from a drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the exploratory dry hole costs are written off and reported as part of Oil Sands and NG exploration expenses in the Consolidated Statements of Earnings. Dry hole expense can fluctuate from year to year due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in the exploratory drilling and the degree of risk in drilling in particular areas.

Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance and/or adjustments in reserves. Such changes may require a test for the potential impairment of capitalized properties based on estimates of future cash flow from the properties. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities and operating costs.

Where management assesses that a property is fully or partially impaired, the book value of the property is reduced to fair value and either completely removed from the company's records ("written off") or partially removed from the company's records ("written down") and reported as part of Oil Sands and NG DD&A expenses in the Consolidated Statements of Earnings.

The company's plant and equipment are depreciated on a straight-line basis over the estimated useful life of the assets. Firebag and NG property costs are depleted on a unit of production (UOP) basis. In each case, the expense is shown on the DD&A line in both the Consolidated Statements of Earnings and in the Schedules of Segmented Earnings. The straight-line basis reflects asset usage as a function of time rather than production levels. For example, the useful life of plant and equipment at Oil Sands base operations and Firebag operations are not based on recorded reserves as the company has access to other undeveloped properties, and bitumen feedstock from third parties, as well as the ability to provide processing services for other producers' bitumen. UOP amortization is used where that method better matches the asset utilization with production with which the asset is associated.

The company determines useful life based on prior experience with similar assets and, as necessary, in consultation with others who have expertise with the assets in question. However, the actual useful life of the assets may differ from management's original estimate due to factors such as technological obsolescence, regulatory requirements and maintenance activity. As the majority of assets are depreciated on a straight-line basis, a 10% reduction in the useful life of plant and equipment would increase annual DD&A by approximately 10%. This impact would be reflected in all business segments with the majority of the impact being in Oil Sands.

Negative revisions in NG reserves estimates will result in an increase in depletion expenses.

Overburden

As part of the process of mining oil sands, it is necessary to remove surface material such as muskeg, glacial deposits and sand. This surface material is referred to as overburden. Overburden removal may precede mining of the oil sands deposit by as much as two years. Accordingly, the quantity of overburden removed in a given period may not bear any relationship to the quantity of oil sands mined in the period, and as such the cash outlays can be different than the amount amortized. In 2004, the overburden amortization charge was $225 million (2003 – $208 million) compared with actual cash overburden spending of $222 million (2003 – $175 million). Oil Sands overburden amortization is reported as part of DD&A in the Consolidated Statements of Earnings. Deferred overburden costs are reported as part of "deferred charges and other" in the Consolidated Balance Sheets.

To ensure that each tonne of oil sands mined is allocated a proportionate share of overburden removal costs, the company has adopted the deferral method of accounting for overburden removal costs whereby all such costs are initially set up as a deferred charge.

To allocate the deferred overburden charges, a life-of-mine approach has been adopted for each mine pit, relating the removal of all overburden (on a volume basis) to the mining of all of the oil sands ore on leases where there is regulatory approval (on a tonnage basis). By adopting this approach, an overburden "stripping ratio" is calculated that relates overburden removal costs to all proved and probable Oil Sands ore reserves. Over time, through a combination of increased mine areas, additional drilling activity and operational experience, the company has seen its stripping ratios vary, which can increase or decrease the overburden amortization costs charged to the earnings statement. In 2004, the stripping ratio increased by approximately 13% due to new operational information and mine plan changes. The effects of the increased stripping ratio were offset by lower per unit overburden removal costs. The net effect of these factors resulted in a $16 million pretax increase in the amount of overburden deferred in the year.

Asset Retirement Obligations (ARO)

Effective January 1, 2004, Suncor adopted the new Canadian accounting standard "Asset Retirement Obligations". Under this standard, the company is required to recognize a liability for the future retirement obligations associated with the company's property, plant, and equipment. An ARO is only recognized to the extent of a legal obligation associated with the retirement of a tangible long-lived asset that Suncor is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the company's total ARO amount. These individual assumptions can be subject to change based on experience.

The ARO is initially measured at fair value and discounted to present value using a credit-adjusted risk-free discount rate of 6% (2003 – 6.5%). The ARO accretes over time until the company settles the obligations and the effect is included in a separate "accretion of asset retirement obligations" expense line in the Consolidated Statements of Earnings. Payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 35 years. The discount rate will be adjusted, when appropriate, to reflect long-term changes in market rates and outlook.

An ARO is not recognized for assets with an indeterminate useful life because the amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of the assets are determinable.

In connection with company reviews of Oil Sands and NG completed in the fourth quarter of 2004, Suncor increased its estimated undiscounted total obligation to approximately $1.1 billion from the previous estimate of $1.0 billion. The increase was due to a change in the Oil Sands estimate to $940 million primarily reflecting increased estimated land reclamation costs related to the south tailings pond. The majority of the costs in Oil Sands are projected to occur over a time horizon extending to approximately 2060. In 2005, these changes in the ARO estimate are anticipated to result in additional after-tax expense of approximately $6 million.

The greatest area of judgment and uncertainty with respect to the company's asset retirement obligations relates to its Oil Sands mining leases where there is a requirement to provide for land productivity equivalent to predisturbed conditions. To reclaim tailings ponds, Suncor is using a process referred to as consolidated tailings technology. At this time, no ponds have been fully reclaimed using this technology, although work is under way. The success and time to reclaim the tailings ponds could increase or decrease the current asset retirement cost estimates. The company continues to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used.

Reserves Estimates

Suncor is a Canadian issuer and is subject to Canadian reporting requirements, including rules in connection with the reporting of its reserves. However, the company has received an exemption from Canadian securities administrators permitting it to report its reserves in accordance with U.S. disclosure requirements. Pursuant to U.S. disclosure requirements, the company discloses net proved conventional oil and gas reserves, including natural gas reserves and bitumen reserves from its Firebag in-situ leases, using constant dollar cost and pricing assumptions. As there is no recognized posted bitumen price, these assumptions are based on a posted benchmark oil price [(1)] adjusted for transportation, gravity and other factors that create the difference ("differential") in price between the posted benchmark price and Suncor's bitumen. Both the posted benchmark price and the differential are generally determined as of a point in time, namely, December 31 ("Constant Cost and Pricing"). Suncor's reserves from its

(1) Under U.S. disclosure requirements, the posted benchmark oil price utilized was Lloydminster light blend, a medium density crude oil and under Annual Average Differential Pricing, the posted benchmark oil price utilized was light sweet at Edmonton, a light density crude oil.

Firebag in-situ leases are reported as barrels of bitumen, using these Constant Cost and Pricing assumptions (see Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves for net proved conventional oil and gas reserves).

Pursuant to U.S. disclosure requirements, Suncor also discloses gross proved and probable mining reserves. The estimate of its mining reserves is based in part on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions. In accordance with these rules, the company reports mining reserves as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80% to 81%. Suncor does not disclose its mining reserves on a net basis as it is continuing to discuss the terms of its option to transition to the Province of Alberta's generic bitumen-based royalty regime in 2009 and accordingly the net mining reserves calculation cannot be estimated (see Required U.S. Oil and Gas and Mining Disclosure – Proved and Probable Oil Sands Mining Reserves). Suncor's Firebag in-situ leases are already subject to royalty based on bitumen, rather than synthetic crude oil. (For a full discussion of Suncor's Oil Sands Crown royalties, see page 24.)

In addition to required disclosure, Suncor's exemption issued by Canadian securities administrators permits it to provide further disclosure voluntarily. Suncor provides this voluntary disclosure to show aggregate proved and probable oil sands reserves, including both mining reserves and reserves from its Firebag in-situ leases. In its aggregate voluntary disclosure, Suncor reports reserves on the following basis:

- Gross proved and probable mining reserves, on the same basis as disclosed pursuant to U.S. disclosure requirements (reported as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80% to 81%); and
- Gross proved and probable bitumen reserves from Firebag in-situ leases, evaluated based on normalized constant dollar cost and pricing assumptions. These assumptions use a posted benchmark oil price as of December 31, but apply a differential generally intended to represent a normalized annual average for the year ("Annual Average Differential Pricing"), rather than a point in time differential, in accordance with Canadian Securities Administrators Staff Notice 51-315 (CSA Staff Notice 51-315). Bitumen reserves estimated on this basis are subsequently converted, for comparison purposes only, to barrels of synthetic crude oil based on a net coker or synthetic crude oil yield from bitumen of 82%.

Accordingly, Suncor's voluntary disclosures of proved and probable reserves from its Firebag in-situ leases will differ from the required U.S. disclosure in three ways. Reserves from Suncor's Firebag in-situ leases are:

- disclosed on a gross basis versus a net basis under U.S. disclosure requirements;
- converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for comparability purposes only; and
- evaluated based on 2004 Annual Average Differential Pricing, in accordance with CSA Staff Notice 51-315, versus Constant Cost and Pricing assumptions pursuant to U.S. disclosure requirements.

Under the U.S. disclosure requirements described above, Suncor announced on January 21, 2005 that it debooked proved reserves from the company's Firebag in-situ leases. December 31, 2004 point-in-time posted benchmark oil prices were unusually low and December 31, 2004 point-in-time diluent prices, which form part of the differential calculation, were unusually high. This combination resulted in a determination that Suncor's proved Firebag in-situ reserves were uneconomic as at December 31, 2004 (see Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves).

Under Suncor's voluntary disclosure, using 2004 Annual Average Differential Pricing, proved Firebag in-situ reserves were determined to be economic and accordingly, are disclosed under Voluntary Oil Sands Reserves Disclosure. Comparisons of these two reserve estimates will show material differences based primarily on the pricing assumptions used, but will also show differences based on whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, and whether the reserves are reported on a gross or net basis.

All of Suncor's oil and gas reserves have been evaluated as at December 31, 2004 by independent petroleum consultants, Gilbert Laustsen Jung Associates Ltd. (GLJ). In reports dated February 9, 2005, and February 17, 2005 (GLJ Oil Sands Reports), GLJ evaluated Suncor's proved and probable reserves on its oil sands mining leases and Firebag in-situ leases respectively, pursuant to both U.S. disclosure requirements using Constant Cost and Pricing assumptions, and CSA Staff Notice 51-315, using 2004 Annual Average Differential Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory approvals have been granted. The mining reserve estimates are based on a detailed geological assessment and also consider industry practice, drill density, production capacity, extraction recoveries, upgrading yields, mine plans, operating life, and regulatory constraints.

For Firebag in-situ reserve estimates, GLJ considered similar factors such as Suncor's regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects, and drill density. Suncor's proved and probable reserves are contained within the AEUB approval area. Proved reserves are delineated with 40 to 80 acre spacing and 3D seismic control while probable reserves are delineated with 80 to 160 acre spacing and 3D seismic control. The major facility expenditures to develop proved undeveloped reserves have obtained final approval by Suncor's Board. Plans to develop the probable undeveloped reserves in subsequent phases are under way but have not yet received final approval from the Board.

In a report dated February 17, 2005 (GLJ NG Report), GLJ also evaluated Suncor's proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from mining leases and the Firebag in-situ reserves) as at December 31, 2004.

More information about the evaluation of Suncor's reserves by GLJ, as well as additional oil and gas data, is available in Suncor's most recent Annual Information Form.

Reserves estimates will continue to be impacted by both drilling data and operating experience, as well as technological developments and economic considerations.

Required U.S. Oil and Gas and Mining Disclosure

Proved and Probable Oil Sands Mining Reserves

Millions of barrels of synthetic crude oil (1)	Gross Oil Sands Mining Leases (2) Proved	Probable	Proved & Probable
December 31, 2003	878	952	1 830
Revisions of previous estimates	140	(105)	35
Extensions and discoveries	—	—	—
Production	(79)	—	(79)
December 31, 2004	**939**	**847**	**1 786**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% to 81%.

(2) Suncor's gross mining reserves are based in part on its current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions.

Suncor does not disclose its mining reserves on a net, after royalty basis as it continues to discuss the terms of its option to transition to the Province of Alberta's generic bitumen based royalty regime in 2009 and accordingly the net mining reserves calculation cannot be estimated (see page 24 for a discussion of our royalty regime).

Proved Conventional Oil and Gas Reserves

The following data is provided on a net basis in accordance with the provisions of the Financial Accounting Standards Board's Statement No. 69 (Statement 69). This statement requires disclosure about conventional oil and gas activities only, and therefore the company's Oil Sands mining activities are excluded, while Firebag in-situ reserves are included.

Net Proved Reserves [2]

Crude Oil, Natural Gas Liquids and Natural Gas

Constant Cost and Pricing as at December 31	Oil Sands business: Firebag – crude oil (millions of barrels of bitumen) [1] [3] [4]	Natural Gas business: crude oil and natural gas liquids (millions of barrels) [5]	Total (millions of barrels)	Natural Gas business: natural gas (billions of cubic feet) [5]
December 31, 2003	424	8	432	456
Revisions of previous estimates	(420) [3]	1	(419)	(23)
Purchases of minerals in place	—	—	—	14
Extensions and discoveries	—	—	—	53
Production	(4)	(1)	(5)	(54)
Sales of minerals in place	—	—	—	—
December 31, 2004	**—**	**8**	**8**	**446**

(1) Oil Sands business – Firebag net reserves means Suncor's undivided percentage interest in total reserves after deducting Crown royalties, freehold and overriding royalty interests. The calculation of these third-party interests is uncertain and based on assumptions about future prices, production levels, operating costs and capital expenditures.

(2) Although Suncor is subject to Canadian disclosure rules in connection with the reporting of its reserves, the company has received exemptive relief from Canadian securities administrators permitting it to report its proved reserves in accordance with U.S. disclosure practices.

(3) Estimates of proved reserves from Suncor's Firebag in-situ leases are based on Constant Cost and Pricing assumptions as at December 31, 2004. Due to unusually low year-end posted benchmark oil prices and unusually high year-end diluent prices, Suncor's proved reserves were determined to be uneconomic as at this year end point in time.

(4) The company has the option of selling the bitumen production from these leases and/or upgrading the bitumen to synthetic crude oil.

(5) Natural Gas business net reserves means Suncor's undivided percentage interest in total reserves after deducting interest of third parties, including Crown royalties, freehold and overriding royalties, calculated following generally accepted guidelines, on the basis of prices and the royalty structure in effect at year end and anticipated production rates. The calculation of these third-party interests is uncertain and based on assumptions about future natural gas prices, production levels, operating costs and capital expenditures. Royalties can vary depending upon selling prices, production volumes, timing of initial production and changes in legislation.

Voluntary Oil Sands Reserves Disclosure

Oil Sands Mining and Firebag In-situ Reserves Reconciliation

The following table sets out, on a gross basis, a reconciliation of Suncor's proved and probable reserves of synthetic crude oil from its Oil Sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from its Firebag in-situ leases, from December 31, 2003 to December 31, 2004, based on the GLJ Oil Sands Reports, in accordance with CSA Staff Notice 51-315, using 2004 Annual Average Differential Pricing assumptions.

Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation

	Oil Sands Mining Leases [1][2]			Firebag In-situ Leases [1][3] (Constant Pricing)			Total Mining and In-situ [4]
Millions of barrels of synthetic crude oil [1]	Proved	Probable	Proved & Probable	Proved [3]	Probable [4]	Proved & Probable	Proved & Probable
December 31, 2003	878	952	1 830	387	1 721	2 108	3 938
Revisions of previous estimates	140	(105)	35	110	179	289	324
Extensions and discoveries	—	—	—	—	—	—	—
Production	(79)	—	(79)	(3)	—	(3)	(82)
December 31, 2004	**939**	**847**	**1 786**	**494**	**1 900**	**2 394**	**4 180**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of between 80% and 81% for reserves under Oil Sands Mining Leases and of 82% for reserves under Firebag In-situ Leases. Although virtually all of Suncor's bitumen from the Oil Sands mining leases is upgraded into synthetic crude oil, the company has the option of selling the bitumen produced from its Firebag in-situ leases and/or upgrading this bitumen to synthetic crude oil and accordingly, these bitumen reserves are converted to synthetic crude oil for comparison purposes only.

(2) Suncor's gross mining reserves are evaluated in part, based on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing assumptions.

(3) Under Required U.S. Oil and Gas and Mining Disclosure, Suncor reported no proved reserves from Firebag in-situ leases. The disclosure in the table above reports proved reserves from these leases and differs in the following three ways. Reserves from Firebag in-situ leases are:
(a) disclosed in this table on a gross basis versus a net basis;
(b) converted from barrels of bitumen to barrels of synthetic crude oil in this table for comparability purposes only; and
(c) evaluated based on Annual Average Differential Pricing assumptions versus point-in-time Constant Cost and Pricing assumptions as at December 31.
Accordingly, Firebag in-situ reserve estimates under Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves and Firebag in-situ proved reserve estimates in this table differ materially.

(4) U.S. companies do not disclose probable reserves for non-mining properties. Suncor voluntarily discloses its probable reserves for Firebag in-situ leases as it believe this information is useful to investors, and allows the company to aggregate its mining and in-situ reserves into a consolidated total for its Oil Sands business. As a result, Suncor's Firebag in-situ estimates are not comparable to these made by U.S. companies.

Employee Future Benefits

The company provides a range of benefits to its employees and retired employees, including pensions and other post-retirement health care and life insurance benefits. The determination of obligations under the company's benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. Management continually reviews these assumptions in light of actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in the company's Consolidated Statements of Earnings and Schedules of Segmented Data. The accrued benefit liability is reported as part of "accrued liabilities and other" in the Consolidated Balance Sheets.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan assets portfolio, the historical level of risk premium associated with other asset classes in the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year-end interest rate on high quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. The accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used. A 1% change in the assumptions at which pension benefits and other post-retirement benefit liabilities could be effectively settled is as noted below.

	Rate of Return on Plan Assets		Discount Rate		Rate of Compensation Increase	
($ millions)	1% Increase	1% Decrease	1% Increase	1% Decrease	1% Increase	1% Decrease
Increase (decrease) to net periodic benefit cost	(4)	4	(11)	12	6	(5)
Increase (decrease) to benefit obligation	—	—	(99)	115	30	(27)

Health care costs comprise a significant element of Suncor's post-employment benefit obligation and an area where there is increasing cost pressure due to an aging North American society. Suncor has assumed an 11.5% annual rate of increase in the per capita cost of covered health care benefits for 2004, with an assumption that this rate will decrease by 0.5% annually, to 5% by 2017, and remain at that level thereafter.

A 1% change in the assumed health care cost trend rate would have the following effect:

($ millions)	1% Increase	1% Decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(1)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	13	(11)

Control Environment

Based on their evaluation as of December 31, 2004, Suncor's chief executive officer and chief financial officer concluded that Suncor's disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by Suncor in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission rules and forms. In addition, other than as described below, as of December 31, 2004, there were no changes in Suncor's internal controls over financial reporting that occurred during 2004 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting. Suncor will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

The company is in the process of implementing an ERP system in all of its businesses to support the company's growth plan. The phased implementation is currently planned to be complete by 2006. Implementing an ERP system on a widespread basis involves significant changes in business processes and extensive organizational training. The company currently believes a phased-in approach reduces the risks associated with making these changes. Suncor believes it is taking the necessary steps to monitor and maintain appropriate internal controls during this transition period. These steps include deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting as part of the reporting, certification and attestation requirements of Section 404 of the U.S. Sarbanes-Oxley Act of 2002. For the year ended December 31, 2004, the company's internal controls were found to be operating free of any material weaknesses. In connection with the continued implementation of its ERP system, the company expects there will be a significant redesign of its business processes during 2005, some of which relate to internal control over financial reporting and disclosure controls and procedures.

Change In Accounting Policies

Asset Retirement Obligations (ARO)

On January 1, 2004, the company retroactively adopted the new Canadian accounting standard related to "Asset Retirement Obligations". Under the new standard a liability is recognized for the future retirement obligations associated with the company's property, plant and equipment. The fair value of the ARO is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation.

Recently Issued Canadian Accounting Standards

Variable Interest Entities

In 2003, Canadian Accounting Guideline 15 (AcG 15), "Consolidation of Variable Interest Entities" (VIEs) was issued. Effective January 1, 2005, AcG 15 requires consolidation of a VIE where the company will absorb a majority of a VIE's losses, receive a majority of its returns, or both. The company will be required to consolidate the VIE related to the sale of equipment as described on page 23. The company does not expect a significant impact on net earnings upon consolidation of the equipment VIE. The impact on the balance sheet will be an increase to property, plant and equipment of $14 million, an increase to inventory of $8 million, and an increase to long-term debt of $22 million. The company's accounts receivable securitization program described on page 23, as currently structured, does not meet the AcG 15 criteria for consolidation by Suncor.

Liabilities and Equity

In 2003, the Canadian Accounting Standards Board approved an amendment to Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" requiring certain obligations that must or could be settled with an entity's own equity instruments to be presented as liabilities. The amendment, effective for the company's 2005 fiscal year and applied on a retroactive basis will affect the company's current presentation of preferred securities as equity. The reclassification of the preferred securities from equity to long-term debt is expected to increase property, plant and equipment by $37 million, and increase 2005 DD&A by $1 million.

oil sands

Located near Fort McMurray, Alberta, Suncor's Oil Sands business forms the foundation of Suncor's growth strategy and represents the most significant portion of the company's assets. The Oil Sands business unit recovers bitumen through mining and in-situ development and upgrades it into refinery feedstock, diesel fuel and byproducts.

Oil Sands strategy focuses on:

- Acquiring long-life mineral leases with substantial bitumen resources in place.
- Sourcing low-cost bitumen supply through mining, in-situ development and third-party supply agreements, and upgrading this bitumen supply into high value crude oil products that meet market demand.
- Increasing production capacity and improving reliability through staged expansion of Oil Sands upgrading facilities.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.

highlights

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2004**	2003	2002
Revenue	**3 596**	3 061	2 616
Production (thousands of bpd)	**226.5**	216.6	205.8
Average sales price ($/barrel)	**42.28**	37.19	33.65
Net earnings	**995**	888	782
Cash flow from operations	**1 752**	1 803	1 475
Total assets	**9 032**	7 934	7 186
Cash used in investing activities	**1 086**	1 055	630
Net cash surplus	**737**	799	729
ROCE (%) (1)	**22.9**	20.8	16.7
ROCE (%) (2)	**18.8**	17.4	15.6

(1) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for Suncor's operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51.

(2) Includes capitalized costs related to major projects in progress.

Significant Developments in 2004 and Subsequent Event

- The start-up phase of stage one of Suncor's Firebag in-situ operation was completed and commercial operations commenced in the second quarter of 2004. Production in 2004 averaged 10,900 barrels per day (bpd) of bitumen, and is expected to reach its full production capacity of 35,000 bpd of bitumen in 2006.
- Cash operating costs from Oil Sands base operations averaged $11.95 per barrel during 2004 at an average natural gas price of US$6.20 per thousand cubic feet (mcf).
- Work to expand Oil Sands production capacity to 260,000 bpd by the end of 2005 continued on schedule and on budget.
- Oil Sands began construction on an estimated $3.6 billion project that, when complete in 2008, is expected to increase production capacity to 350,000 bpd.
- On January 4, 2005, a fire occurred in Upgrader 2, primarily affecting a coker fractionator. As a result, base plant production capacity at Oil Sands has been temporarily reduced to about 110,000 bpd from about 225,000 bpd. Based on a preliminary assessment of the damage, Suncor estimates that production should return to full rates of approximately 225,000 bpd sometime during the third quarter, 2005.

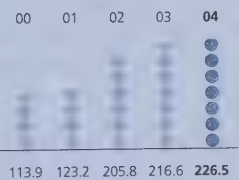
Analysis of Net Earnings

Net earnings were $995 million in 2004 compared to $888 million in 2003. The increase was largely driven by higher benchmark commodity prices (net of the effect of widening light/heavy crude oil differentials), higher sales volumes related to higher overall production, and reductions in year-over-year non-cash income tax expenses due to changes in tax rates and resource allowance deductions. These positive factors were largely offset by increased hedging losses, higher Oil Sands Alberta Crown royalties, and the impact of a stronger Canadian dollar.

Oil Sands average production was 226,500 bpd in 2004, compared to 216,600 bpd in 2003. The increase in 2004 was largely due to new in-situ bitumen production

of 10,900 bpd. Base plant production in 2004 was lower than expected due to unplanned upgrader maintenance. In addition, 2004 in-situ bitumen production was lower than anticipated due to unscheduled water treatment system maintenance in the third quarter. Production volumes in 2003 were from base operations only, and reflect the impact of a 30-day maintenance shutdown of Upgrader 1.

Production
(thousands of bpd)

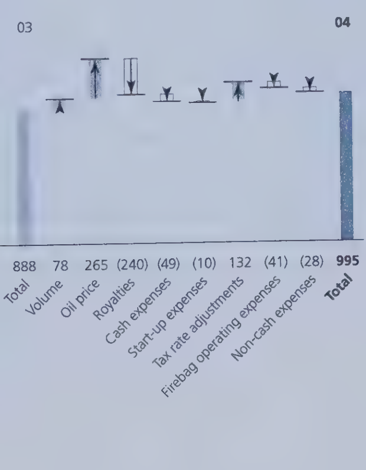


Sales volumes in 2004 averaged 226,300 bpd compared with 218,300 bpd in 2003. Higher sales volumes increased 2004 net earnings by $78 million.

Sales prices averaged $42.28 per barrel in 2004 (including the impact of pretax hedging losses of $621 million) compared with $37.19 per barrel in 2003 (including the impact of pretax hedging losses of $239 million). The average price realization was favourably impacted by the strengthening of U.S. dollar West Texas Intermediate (WTI) benchmark crude oil prices (net of widening light/heavy crude oil differentials), partially offset by the continued strengthening of the Canadian dollar from an average exchange rate of US$0.72 in 2003 to US$0.77 in 2004. Because crude oil is sold based on U.S. dollar benchmark prices, the narrowing exchange rate decreased the Canadian dollar value of crude oil products.

The net impact of the above pricing factors increased earnings by $265 million in 2004.

Bridge Analysis of Net Earnings
($ millions)



Cash Expenses

Cash expenses increased to $1.17 billion from $1.03 billion in 2003. Expenses were higher year-over-year due to the following factors:

- Purchases of crude oil and products increased to $75 million in 2004 from $12 million in 2003. The increase is primarily due to the repurchase of crude oil originally sold to a Variable Interest Entity (VIE) in 1999.
- The first year of in-situ operations increased cash expenses by $64 million in 2004, including natural gas purchases of $39 million.
- Upgrading costs increased by $26 million primarily due to unscheduled maintenance.

These higher expenses were partially offset by lower transportation costs and other costs of $13 million. Overall, increases in cash expenses reduced 2004 net earnings by $49 million.

Royalties

Oil Sands Alberta Crown royalties increased by $374 million to $407 million in 2004 compared to $33 million in 2003. Increased royalties reduced net earnings by approximately $240 million. For a further discussion on Crown royalties, see page 24.

Start-up Expenses

Project start-up expenses increased by $16 million ($10 million after tax) in 2004, due to commissioning and start-up expenses for in-situ operations during the first quarter of 2004.

Non-cash Expenses

Non-cash depreciation, depletion and amortization (DD&A) expense, including overburden amortization expense, increased to $503 million from $458 million in 2003. The increase was primarily due to first-time DD&A expenses from in-situ operations of $20 million, higher overburden amortization of $16 million, and higher maintenance shutdown and catalyst amortization. Higher non-cash expenses decreased net earnings by $28 million.

In 2004, Oil Sands average overburden removal stripping ratio was 0.52 cubic metres of overburden for every tonne of ore mined, compared to 0.46 cubic metres per tonne in 2003. The increased stripping ratio year-over-year was primarily due to higher proportionate levels of mining activity from the Millennium mine, which has a higher stripping ratio than the Steepbank mine, as well as updated drilling results that provided more detailed information. Overburden amortization increased to $224 million in 2004 compared with $208 million in 2003.

Stripping ratios are expected to continue to increase until 2006 as proportionately more mining activity is conducted at the company's Millennium mine. From 2006 to 2010 it is expected that all mining production will come from the Millennium mine and the stripping ratio will stabilize. (For a discussion of overburden stripping ratios see page 29.)

Due to the use of judgment and the extended time frame associated with the company's stripping ratio and bitumen recovery estimates, actual results may differ, and these differences may be significant.

Tax Adjustments

In 2004, non-cash income tax expense was reduced by $53 million relating to reductions in the Alberta provincial tax rate. In 2003, non-cash income tax expense increased by $93 million primarily related to the impact of changes in the federal government's taxation policies for the resource sector, and an increase in Alberta and Ontario provincial tax rates. Including other minor differences, changes in effective tax rates increased net earnings by $132 million in 2004 compared to 2003.

Operating Costs

With the start of Firebag in-situ operations, Suncor reported cash operating costs from mining and upgrading production from the mine (base operations) separately from cash costs from in-situ operations. Cash operating costs for base operations increased to $949 million ($11.95 per barrel) in 2004 compared to $907 million ($11.45 per barrel) in 2003, primarily as a result of higher maintenance costs, offset by lower natural gas costs.

Natural gas purchases for base operations averaged approximately 65 million cubic feet per day (mmcf/d) in 2004, consistent with the prior year. Oil Sands natural gas costs declined to $6.74 per mcf in 2004 from $6.95 per mcf in 2003, reducing cash costs by approximately $0.15 per barrel.

Net Cash Surplus Analysis

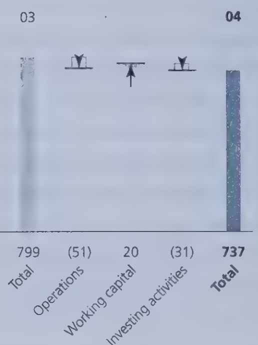
Cash flow from operations was $1.75 billion in 2004, a slight decrease from $1.8 billion in 2003. Excluding the impact of non-cash income tax adjustments, the decrease was due to the same factors that increased net earnings, offset by higher cash overburden and reclamation spending, and higher pension funding requirements.

Net working capital decreased by $71 million in 2004 compared to a decrease of $51 million in 2003. Higher accounts receivable due to higher sales volumes and higher price realizations in the final month of 2004 compared to 2003 was more than offset by increased accounts payable and accrued liabilities related to increased capital spending in the fourth quarter and higher accrued royalties payable.

Cash flow used in investing activities increased slightly to $1.09 billion in 2004 compared to $1.06 billion in 2003. During 2004, capital spending related primarily to construction of Firebag stage two, the Millennium vacuum unit, and engineering and preliminary construction of the Millennium Coker Unit. During 2003, capital spending primarily related to construction of Firebag stage one, and engineering and preliminary construction of the Millennium Vacuum Unit, as well as spending on the planned maintenance shutdown of Upgrader 1.

Combined, the above factors resulted in a net cash surplus of $737 million in 2004, compared with a surplus of $799 million in 2003.

Bridge Analysis of Net Cash Surplus
($ millions)



Subsequent Event

A fire on January 4, 2005, caused significant damage to Oil Sands Upgrader 2, reducing upgraded crude oil production capacity from base operations to about 110,000 bpd. Repair work is under way and Oil Sands expects to return to full production capacity of 225,000 bpd in the third quarter of 2005.

The timeline for recovery work is preliminary and subject to change. Further inspection of the damaged equipment will occur as the repairs progress. Any new information could modify the timetable for returning to full production.

To mitigate the impact of reduced production during the recovery period, Oil Sands plans to bring forward as many maintenance projects as possible, including all, or significant portions of, a maintenance shutdown previously planned for the fall.

Suncor's preliminary investigation into the cause of the fire suggests the issue was an isolated case.

Outlook

As a result of the January fire, specific targets for Oil Sands production, sales mix and cash operating costs are not available. Fire recovery efforts are not expected to impact expansion efforts and work to continue specific growth targets continues.

Expansion to 260,000 bpd

Work is proceeding on schedule to increase production capacity to 260,000 bpd by the end of 2005. To achieve this goal, Oil Sands must complete construction of the Millennium vacuum unit, tie in bitumen feed infrastructure and commission the new facility. The project is on budget to meet its estimated cost of $425 million.

Expansion to 350,000 bpd

The next stage of growth, expected to increase production capacity to 350,000 bpd, is also proceeding on schedule and on budget. This project is expected to reach several milestones with fabrication and transport of major vessels for the coker unit expansion scheduled to be completed during 2005.

The total cost of this project is estimated at $3.6 billion, including approximately $2.1 billion to expand Upgrader 2 and $1.5 billion to increase bitumen supply.

Incremental bitumen to feed expanded upgrading capacity is also expected to be provided under a processing agreement between Suncor and Petro-Canada, slated to take effect in 2008. Under the agreement, Oil Sands will process at least 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada will retain ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, Suncor will sell an additional 26,000 bpd of Suncor proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

Expansion to 500,000 bpd to 550,000 bpd

In planning for expansion beyond 2008, Suncor expects to file regulatory applications in 2005 to construct a third upgrader and expand its mining/extraction and in-situ operations, key steps to increasing production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. Cost estimates for this project, known as Voyageur, are not yet available. Approval by regulators and Suncor's Board of Directors is required before the project can proceed.

Production Plan

Description	Regulatory Approval	Board of Directors Approval	Cost Estimate (1)	Production Capacity (bpd)	Status
Millennium vacuum unit	Yes	Yes	$425 million	260 000	Millennium vacuum unit under construction. Project is on schedule and on budget.
Coker unit expansion and expanded mining and in-situ operations	Yes	Firebag stage 2 and coker unit expansion approved. Additional Firebag stages and mining/ extraction subject to approval.	$3.6 billion	350 000 in 2008	Construction under way. Project is on schedule and on budget.
Potential third upgrader – asset configuration still to be determined	No	No	Not available	500 000 to 550 000 in 2010 to 2012	Regulatory application expected to be filed in 2005.

(1) These cost estimates are based on preliminary engineering. Actual amounts will differ and the differences may be material.

Mine Extension

As part of its regulatory filing for Voyageur, Oil Sands also intends to file for approval to construct and operate an extension of the Steepbank mine. The proposed development would replace ore production that is expected to be depleted prior to the end of the decade. Currently, capital development costs are estimated at $350 million. Approval by regulators and Suncor's Board of Directors is required before construction can proceed.

To support the company's mine development plan, in January 2005, Oil Sands submitted a regulatory application to build a new primary extraction plant in closer proximity to mining operations. The cost of constructing the new extraction facility and decommissioning the existing plant has been estimated at $320 million.

Operating Licence Renewal

During 2005, Oil Sands will be required to update its 10-year operating licence by filing a renewal application with regulators. Management does not expect the operating licence renewal to affect its growth plans.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance include, but are not limited to, the following:

- Final amount and timing of the settlement and payment of insurance proceeds related to fire damage and interruption of business at Oil Sands.
- Additional maintenance or updated maintenance schedules related to returning Oil Sands to full production as well as delay or extension of work to tie in major vessels required to expand operations.
- Suncor's ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to Suncor Overview, Liquidity and Capital Resources on page 21.
- The ability to complete future projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for skilled people, increased demands on the Fort McMurray infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the operations. Suncor continues to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Suncor's strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding its customer base and offering a variety of blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices and exchange factors and the light/heavy and sweet/sour crude oil differentials. Prices and differentials are difficult to predict and impossible to control.
- Suncor's relationship with its trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 53 under Forward-looking Statements. Also refer to Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

natural gas

Suncor's Natural Gas (NG) business primarily produces conventional natural gas in Western Canada. NG's production serves as a price hedge that provides the company with a degree of protection from volatile market prices of natural gas purchased for internal consumption.

NG's strategy is focused on:

- Building competitive operating areas.
- Improving base business efficiency.
- Creating new, low-capital business opportunities.

NG's long-term goal is to achieve a sustainable return on capital employed (ROCE) of 12% at mid-cycle prices of US$4.00 to US$4.50 per thousand cubic feet (mcf). To ensure natural gas production keeps pace with company-wide natural gas purchases, NG is targeting production increases of 3% to 5% per year.

highlights

Summary of Results

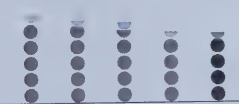
Year ended December 31 ($ millions unless otherwise noted)	**2004**	2003	2002
Revenue	**567**	512	339
Natural gas production (mmcf/d)	**200**	187	179
Average natural gas sales price ($/mcf)	**6.70**	6.42	3.91
Net earnings	**115**	120	34
Cash flow from operations	**319**	298	164
Total assets	**965**	763	793
Cash used in investing activities	**251**	166	158
Net cash surplus	**67**	143	28
ROCE (%) (1)	**27.1**	29.2	9.5

(1) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51.

Significant Developments During 2004

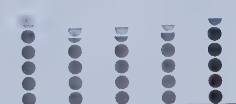
- Natural gas production increased 7% to 200 million cubic feet per day (mmcf/d) in 2004 compared to purchases of approximately 120 to 130 mmcf/d. Favourable drilling results in the Foothills and Northern operating areas were a major factor in delivering volume additions.
- Higher revenues due to increased production and higher commodity prices were offset by higher royalties and higher depreciation, depletion and amortization (DD&A).
- The divestment of 62.5% of NG's interest in Suncor's Simonette gas plant yielded a $13 million after-tax gain.

Total Net Proved Reserves
(millions of boe) (2)



	00	01	02	03	**04**
Natural gas liquids and crude oil	11	10	10	8	**8**
Natural gas	95	91	86	76	**74**
Total	106	101	96	84	**82**

Production
(thousands of boe/d) (2)



	00	01	02	03	**04**
Natural gas liquids and crude oil	7.2	3.9	3.9	3.7	**3.5**
Natural gas	33.3	29.5	29.8	31.2	**33.3**
Total	40.5	33.4	33.7	34.9	**36.8**

(2) For details on barrels of oil equivalent (boe), see page 14.

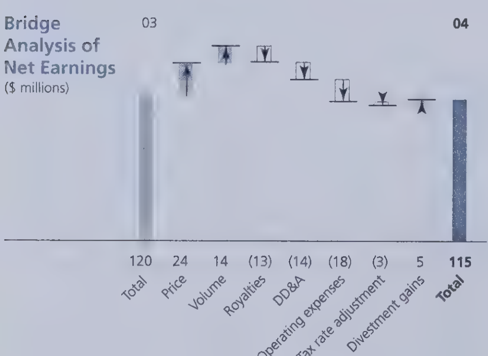
Analysis of Net Earnings

NG net earnings were $115 million in 2004, compared to $120 million in 2003. Higher production volumes, higher realized natural gas prices, and divestment gains were more than offset by higher DD&A, higher royalty expenses, and the costs of the final arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001.

NG's average natural gas production increased to 200 mmcf/d in 2004 from 187 mmcf/d in 2003. Including liquids, total 2004 production was 36,800 boe/d compared with 34,900 boe/d in 2003. Higher production volumes increased earnings by $14 million in 2004.

In 2004, NG's average realized price for natural gas was $6.70 per mcf, an increase of 4% over the average $6.42 per mcf realized in 2003. Price realizations for NG's crude oil and natural gas liquids production were also higher in 2004 due to higher benchmark crude oil prices. The combined impact of the above pricing factors increased earnings in 2004 by $24 million.

Bridge Analysis of Net Earnings
($ millions)



Expenses

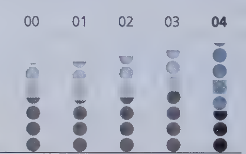
Royalties on NG production were $124 million ($9.22 per boe) in 2004, compared to $106 million ($8.32 per boe) in 2003. The higher royalties, which reflect higher average commodity prices and increased production, reduced after-tax earnings by $13 million.

DD&A expenses increased to $115 million in 2004 from $91 million in 2003. The increase of $14 million after tax was due to a higher cost base subject to depletion, higher production, and a lower proved reserve base.

Operating costs increased to $100 million in 2004 from $73 million in 2003 due primarily to the final arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001. The settlement reduced earnings by $12 million after tax. Operating costs were also impacted by higher volumes and higher processing charges, which reduced earnings by $6 million after tax for a total reduction in earnings of $18 million after tax.

Divestment gains increased to $19 million in 2004 ($13 million after tax) from $12 million ($8 million after tax) in 2003 primarily due to the sale of a 62.5% interest in NG's Simonette gas plant for proceeds of $19 million and an after-tax gain of $13 million. NG and its partner are in the process of expanding the capacity of the plant and building a new pipeline to connect the facility with volumes produced from the Cabin Creek and Solomon fields in the Alberta Foothills. In 2003, NG divested its Mackenzie Delta non-core assets for an after-tax gain of $8 million. The higher divestment gains in 2004 as compared to 2003 increased earnings by $5 million after tax.

Lifting and Administration Costs
($/boe)



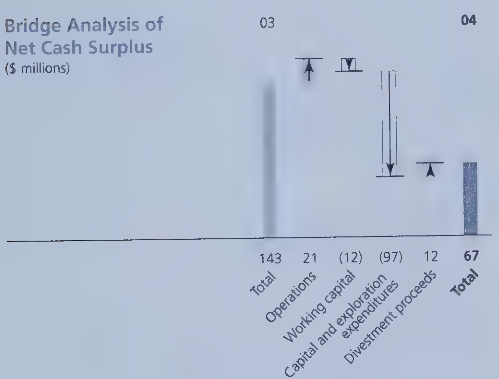
	00	01	02	03	**04**
Administration	1.96	2.21	2.34	2.35	**2.39**
Lifting	3.11	2.96	3.15	3.48	**3.84**
Total	5.07	5.17	5.49	5.83	**6.23**

Net Cash Surplus Analysis

NG's net cash surplus was $67 million in 2004 compared with $143 million in 2003. Cash flow from operations increased to $319 million compared with $298 million in the prior year, largely due to increased production and higher commodity prices, partially offset by the Enron settlement and higher royalties. Changes in net working capital in 2004 resulted in a use of cash of $1 million, compared with a source of cash of $11 million in 2003, due primarily to an increase in accounts receivable.

Cash used in investing activities increased to $251 million compared with $166 million in 2003 as a result of an asset acquisition and higher capital and exploration costs, partially offset by proceeds from disposal of the Simonette gas plant. On December 29, 2004, NG acquired assets in eastern British Columbia for $33 million. These assets generate approximately 6 mmcf/d of production and consist of developed and undeveloped land.

Bridge Analysis of Net Cash Surplus
($ millions)



Outlook

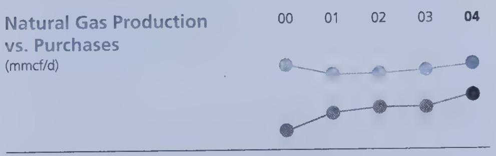
NG's long-term financial goal is to achieve a sustainable ROCE of 12% at mid-cycle natural gas prices (US$4.00 to US$4.50/mcf). To meet this goal, management plans to continue to build competitive operating areas, grow natural gas production, improve base business efficiency and focus on strict cost control.

NG continues to work towards an operational target of increasing production by 3% to 5% per year to keep pace with the company's growing internal natural gas demands. To meet this goal, in 2005 NG is targeting average production of 205 to 210 mmcf/d and approximately 3,300 bpd of crude oil and natural gas liquids.

NG will continue to leverage its expertise and existing assets to bring reserves into production in Western Canada. However, increasing production will likely require expansion through farm-ins(1), joint-ventures or additional property acquisitions, which could expand the size and number of operating areas, or could involve new operating areas outside of Western Canada.

To support these goals, the company has budgeted $260 million in capital spending for exploration and development in 2005.

Natural Gas Production vs. Purchases
(mmcf/d)



	00	01	02	03	**04**
Production	200	177	179	187	**200**
Purchases	44	87	99	100	**130**

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the NG business include, but are not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically. Positive or negative reserve revisions arising from technical and economic factors can have a corresponding positive or negative impact on asset valuation and depletion rates.
- The impact of market demand for land and services on capital and operating costs. Market demand and the availability of opportunities also influences the cost of acquisitions and the willingness of competitors to allow farm-ins on prospects.
- Risks and uncertainties associated with obtaining regulatory approval for exploration and development activities in Canada and the United States. These risks could add to costs or cause delays to projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 53 under Forward-looking Statements. Refer to the Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

(1) Acquisitions of all or part of the operating rights from the working interest owner. The acquirer assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty but may retain any type of interest.

energy marketing and refining – canada

Energy Marketing and Refining – Canada (EM&R) operates a 70,000 barrel per day (bpd) (approximately 11,100 cubic metres per day) capacity refinery in Sarnia, Ontario and markets refined products to industrial, wholesale and commercial customers primarily in Ontario and Quebec. Through its Sunoco-branded and joint-venture operated service networks, the business unit markets products to retail customers in Ontario. EM&R's business also encompasses third-party energy marketing and trading activities, as well as providing marketing services for the sale of crude oil and natural gas from the Oil Sands and NG operations.

EM&R's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability and product yields and enhancing operational flexibility to process a variety of feedstock, including crude oil streams from Oil Sands operations.
- Increasing the profitability and efficiency of retail networks by improving average site throughput and growing non-fuel ancillary retail revenue.
- Creating downstream market opportunities to capture greater long-term value from Oil Sands production.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and customers and continuous improvement of operations.

As a marketing channel for Suncor's refined products, EM&R's Ontario retail networks generated approximately 58% of EM&R's total 2004 sales volumes of 97,000 bpd. EM&R's retail networks are comprised of 278 Sunoco-branded retail service stations, 23 Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint-venture(1) businesses that operate 147 Pioneer-branded retail service stations, 52 UPI-branded retail service stations and 14 UPI bulk distribution facilities for rural and farm fuels. Wholesale and industrial sales were responsible for approximately 37% of EM&R's refined product sales in 2004. Sun Petrochemicals Company (SPC), a 50% joint-venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 5% of sales.

highlights

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	**2004**	2003	2002
Revenue	**3 460**	2 936	2 508
Refined product sales (millions of litres)			
Sunoco retail gasoline	**1 665**	1 599	1 642
Total	**5 643**	5 477	5 286
Net earnings (loss) breakdown:			
Total earnings excluding energy, marketing and trading activities	**68**	67	23
Energy marketing and trading activities	**12**	(2)	3
Gain on sale of retail natural gas marketing business	**—**	—	35
Tax adjustments	**—**	(12)	—
Total net earnings	**80**	53	61
Cash flow from operations	**188**	164	112
Cash used in investing activities	**259**	135	34
Net cash surplus (deficiency)	**(21)**	29	63
ROCE (%)(1)	**14.6**	10.3	12.0
ROCE (%)(2)	**13.6**	10.3	12.0

(1) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for Suncor's operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51.

(2) Includes capitalized costs related to major projects in progress.

Significant Developments During 2004

- EM&R started construction on the diesel desulphurization unit at the Sarnia refinery. This project will allow the company to meet federal low-sulphur diesel fuel regulations that take effect in 2006. The project, which is estimated to cost $800 million, is also expected to enable it to process approximately 40,000 bpd of Oil Sands sour crude blends.

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(1) Pioneer Group Inc. is an independent company with which Suncor has a 50% joint-venture partnership. UPI Inc. is a 50% joint-venture company with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

- Pre-development engineering, formal public consultation, preliminary project planning and regulatory approval applications were completed for a planned ethanol plant in the Sarnia region. In February 2004, Suncor received approval by Natural Resources Canada's (NRCan) Ethanol Expansion Program on its proposal for funding on the project. Subject to final approvals, NRCan would contribute $22 million towards Suncor's construction of the $120 million ethanol production facility. During the year, Suncor finalized the site location for the plant.
- EM&R completed its interior store renewal program and also started an exterior re-imaging program of all convenience stores. Same site convenience store sales increased 20% over 2003, while same site convenience store royalties increased more than 10%.

Analysis of Net Earnings

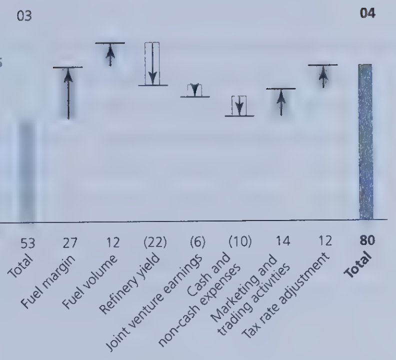
EM&R has historically reported its segmented results on a Rack Back/Rack Forward divisional basis. The Rack Back division included Ontario refining operations, as well as sales and distribution to the Sarnia refinery's largest industrial and reseller customers and the SPC joint-venture. Rack Forward included retail operations, cardlock and industrial/commercial sales, as well as the UPI and Pioneer joint-ventures.

Effective for 2004, EM&R's Rack Back and Rack Forward organizational structures were consolidated into one unit for the purposes of external segmented reporting. Prior year amounts have been reclassified to conform to the current year's presentation. EM&R's external results continue to be measured and analysed on a margin basis.

EM&R results also include the impact of Suncor's third-party energy marketing and trading activities that are discussed separately on page 46.

EM&R's net earnings increased to $80 million in 2004 from $53 million in 2003. This increase was primarily due to higher refining margins, higher sales volumes, improved refinery utilization, mark-to-market gains on inventory related derivatives, and the impact of 2003 tax adjustments. These positive impacts were partially offset by higher product purchase costs, higher cash and non-cash refinery operating expenses, and lower joint-venture earnings.

Bridge Analysis of Earnings
($ millions)



Margins

After-tax refined product margins increased by $27 million in 2004 compared to 2003, due to higher refining margins in gasoline, chemicals, diesel and jet fuel, partially offset by reduced refining margins in other products such as fuel oil and propane and decreases in retail gasoline margins. Refining margins on Suncor's proprietary refined products averaged 8.0 cents per litre (cpl) in 2004, compared to 6.5 cpl in 2003. The 23% increase was largely a result of strong refined product demand and tight North American inventory supply. Sunoco-branded retail gasoline margins averaged 4.4 cpl in 2004, compared with 6.6 cpl in 2003. The decrease was primarily due to higher crude prices and intense price competition in Ontario markets. Price competition also contributed to a decrease of $6 million in joint-venture net earnings in 2004.

Volumes

Total sales volumes averaged 97,000 bpd (15,400 cubic metres per day) in 2004, up from 94,400 bpd (15,000 cubic metres per day) in 2003, resulting in an increase in net earnings of $12 million. Higher sales of gasoline, jet and diesel fuel were partially offset by lower sales of propane and heavy fuel oils. Total gasoline sales volumes in the Sunoco-branded retail network increased to 1,665 million litres in 2004 from 1,599 million litres in 2003. Average Sunoco-branded service station site throughput was 6.2 million litres per site in 2004 compared to 5.9 million litres per site in 2003. Site throughput is an important indicator of network efficiency. EM&R's Ontario retail gasoline market share, including all Sunoco and joint-venture operated retail sites was 19%, unchanged from 2003. Approximately 94% of EM&R's refined products were sold to the Ontario market in 2004.

Refinery Utilization

Overall refinery utilization averaged 100% in 2004, compared with 95% in 2003. The impact of scheduled and unscheduled maintenance shutdowns to portions of the refinery in the second quarter of 2004 was more than offset by above capacity utilization during the rest of the year. In 2003, utilization was below capacity primarily due to the impacts of a widespread power outage in the northeastern United States and southern Ontario during August, as well as a planned 32-day maintenance shutdown on a portion of the refinery.

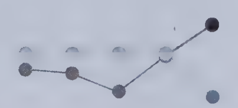
Product Purchase Costs

The favourable impacts of improved refined product margins, higher volumes and higher refinery utilization were partially offset by higher third-party refined product purchase costs in 2004 compared to 2003. Refined product purchase costs increased primarily due to higher commodity prices for both purchased refined products and feedstock, partially offset by lower required purchased volumes of refined products to meet customer needs. Purchased volumes were higher in 2003 due to the power outage noted above. In total, increased purchase costs reduced 2004 net earnings by $22 million.

Cash and Non-cash Operating Expenses

Overall, cash and non-cash operating expenses increased by $10 million in 2004 compared to 2003. Cash expenses increased by $9 million in 2004, due to higher energy and freight costs, partially offset by lower salaries and benefits and lower refinery maintenance expenses. Non-cash expenses increased by $9 million in 2004, due to increased depreciation as a result of a higher asset base. These increases were partially offset by higher mark-to-market gains of $8 million on inventory-related derivatives.

Margins
(cpl)



	00	01	02	03	**04**
Retail gasoline margin	6.6	6.6	6.6	6.6	**4.4**
Refining margin	5.9	5.7	4.8	6.5	**8.0**

Related Party Transactions

The Pioneer, UPI and SPC joint-ventures are considered to be related parties to Suncor for GAAP purposes. EM&R supplies refined petroleum products to the Pioneer and UPI joint-ventures, and petrochemical products to SPC. Suncor has a separate supply agreement with each of Pioneer, UPI and SPC. These supply agreements are evergreen, subject to termination only in accordance with the various agreements between the parties.

The following table summarizes the company's related party transactions with Pioneer, UPI and SPC, after eliminations, for the year. These transactions are in the normal course of operations and have been conducted on the same terms as would apply with unrelated parties.

($ millions)	**2004**	2003	2002
Operating revenues			
Sales to EM&R joint-ventures:			
Refined products	**320**	301	321
Petrochemicals	**272**	187	142

At December 31, 2004, amounts due from EM&R joint-ventures were $17 million, compared to $36 million at December 31, 2003.

Sales to, and balances with, EM&R joint-ventures are established and agreed to by the related parties and approximate fair value.

Energy Marketing and Trading Activities

Third-party energy marketing and energy trading activities consist of both third-party crude oil marketing and financial and physical derivatives trading activities. These activities resulted in net earnings of $12 million in 2004 compared to a net loss of $2 million in 2003.

Energy trading activities, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities.

Tax Adjustments

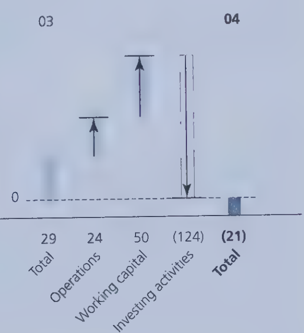
In 2003, EM&R net earnings included a $12 million future income tax charge due to the repeal of previously announced reductions in income tax rates by the Ontario government.

Net Cash Deficiency Analysis

EM&R's net cash deficiency was $21 million in 2004 compared to a net cash surplus of $29 million in 2003. Cash flow from operations increased to $188 million in 2004 from $164 million in 2003 due to the same factors impacting net earnings. Net working capital decreased by $50 million in 2004, compared to no change in 2003. The decrease in net working capital is a result of increased accounts payable related to capital expenditures on the desulphurization project and higher purchased crude payables resulting from higher commodity prices.

The favourable impacts of the increased cash flow from operations and working capital were more than offset by an increase in cash used in investing activities, which increased to $259 million in 2004 from $135 million in 2003. The increase was primarily due to higher capital expenditures associated with the diesel desulphurization project at the Sarnia refinery, as well as increased refinery capital maintenance expenditures.

Bridge Analysis of Net Cash Surplus/(Deficiency)
($ millions)



Outlook

In 2004, Suncor started construction on a diesel desulphurization project at the company's Sarnia refinery to meet current and anticipated federal sulphur regulations. Under the terms of an agreement with Shell Canada Products (Shell), the project facilities will also be used to process high-sulphur diesel from Shell's Sarnia refinery into low-sulphur diesel on a fee-for-service basis. The project will also include capital expenditures to expand the refinery's throughput capacity and enable it to process approximately 40,000 bpd of Oil Sands sour crude blends. When all components are completed in 2007, Suncor expects this project will cost a total of approximately $800 million.

Construction of a planned ethanol plant is expected to begin in 2005 and be completed by 2006, subject to regulatory approvals. This facility is expected to produce ethanol at a capacity of 200 million litres per year for blending into Sunoco-branded and Suncor joint-venture retail gasolines. The total project is expected to cost $120 million.

EM&R expects total capital spending to be approximately $400 million in 2005, with the majority directed towards meeting regulations for diesel desulphurization at the Sarnia refinery.

As a result of a fire at Oil Sands, during 2005, EM&R may be required to purchase additional synthetic crude oil feedstock to meet customer demand, resulting in higher purchased product costs.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the EM&R business include, but are not limited to, the following:

- Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.
- There are certain risks associated with the execution of capital projects, including the risk of cost overruns. The diesel desulphurization project must be completed prior to June 1, 2006, to ensure compliance with legislative requirements. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.
- Environment Canada is expected to finalize regulations reducing sulphur in off-road diesel fuel and light fuel oil to take effect later in the decade. Suncor believes that if the regulations are finalized as currently proposed, the new facilities for reducing sulphur in on-road diesel fuel should also allow the company to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 53 under Forward-looking Statements. Refer to the Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

refining and marketing – u.s.a.

In August 2003, Suncor acquired downstream assets based in Denver, Colorado, to create a U.S. Refining and Marketing business unit (R&M). The business operates a 60,000 barrel per day (bpd) (approximately 9,500 cubic metres per day) capacity refinery located in the Denver, Colorado area that markets refined products to customers primarily in Colorado, including retail marketing through 43 Phillips 66-branded retail stations in the Denver area. Assets also include a 100% interest in the 480-kilometre Rocky Mountain pipeline system and a 65% interest in the 140-kilometre Centennial pipeline system.

This acquisition is part of an integration strategy aimed at improving access to the North American energy markets through acquisitions, long-term contracts and possible joint-ventures.

R&M's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability, product yields and operational flexibility to process a variety of feedstocks, including crude oil streams from Oil Sands operations.
- Increasing the profitability and efficiency of its retail network.
- Creating additional downstream market opportunities in the United States to capture greater long-term value from Oil Sands production.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and customers and continuous improvement of operations.

The following analysis has been prepared on the basis of a comparison of an entire year of operations in 2004 compared to five months in 2003. This has the impact of increasing measures related to earnings, margins, volumes and expenses in 2004 compared to 2003.

highlights

Summary of Results

Year ended December 31 (Cdn$ millions unless otherwise noted)	2004	2003(1)
Revenue	**1 495**	515
Refined product sales		
(millions of litres)		
Gasoline	**1 627**	636
Total	**3 504**	1 384
Net earnings	**34**	18
Cash flow from operations	**59**	34
Investing activities	**198**	300
Net cash surplus (deficiency)	**(71)**	(220)
ROCE (%) (2)	**12.2**	—
ROCE (%) (3)	**11.0**	—

(1) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

(2) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for Suncor's operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51. For 2003, represents five months of operations since acquisition August 1, therefore no annual ROCE was calculated.

(3) Includes capitalized costs related to major projects in progress.

Significant Developments During 2004

- R&M started construction on a project to modify the Denver refinery to allow the company to meet regulations that take effect on June 1, 2006, requiring lower sulphur diesel fuel. It is also expected that modifications will enable R&M to process 10,000 bpd to 15,000 bpd of Oil Sands sour crude while also increasing the refinery's ability to process a broader slate of bitumen-based crude oil. The capital budget for this project is approximately $360 million (approximately US$300 million).
- A scheduled maintenance shutdown on certain refinery units was successfully completed in the second quarter of 2004.
- Approximately 6% of feedstock processed at the Denver refinery was supplied from Oil Sands operations, a significant step forward in Suncor's integration strategy.

Analysis of Net Earnings

R&M's external results are measured and analysed on a net margin basis.

R&M's net earnings were $34 million in 2004 compared to $18 million in 2003. In addition to the positive impact of an entire year of operations in 2004 compared to five months of operations in 2003, the increase was due to higher average refining margins and higher average sales volumes. These positive impacts were partially offset by higher product purchase costs, higher cash and non-cash refinery operating expenses, and lower refinery utilization during the first two quarters of 2004.

Margins

Average refining margins were 6.8 cents per litre (cpl) in 2004 compared to 5.9 cpl in 2003 reflecting significantly higher gasoline and diesel margins, partially offset by lower net realizations on asphalt and other heavy product sales. Higher refined product margins in 2004 increased earnings by $13 million. Retail margins were 5.4 cpl in 2004, compared to 5.6 cpl in 2003, reflecting weaker retail gasoline prices during the second and third quarters of 2004.

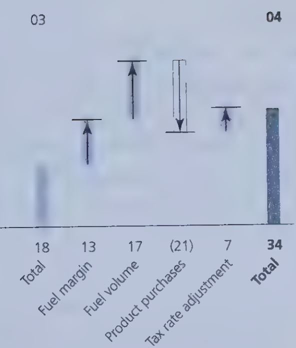
Volumes and Refinery Utilization

Sales volumes increased in 2004 due to seven more months of operations in 2004 compared to 2003. In addition, sales volumes increased by 5,800 bpd (900 cubic metres) in the last five months of 2004 as compared to the same period in 2003, primarily due to higher refinery utilization rates and decreases in refined inventory levels due to strong customer demand. Overall, the higher volumes resulted in an increase in net earnings of $17 million.

Refinery utilization in the first half of 2004 was negatively impacted by a planned 19-day maintenance shutdown on certain refinery units during the second quarter, as well as first quarter operating difficulties that were rectified during the shutdown.

Partially offsetting the positive impacts of higher margins and volumes, increased refined product purchases reduced net earnings by $21 million. The higher volume of purchased refined products was primarily due to meeting customer demand during the maintenance shutdown.

Bridge Analysis of Earnings
($ millions)



Cash and Non-cash Expenses

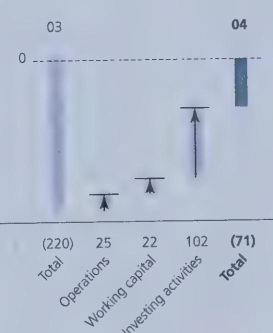
Increases in refinery cash expenses and non-cash depletion, depreciation and amortization were proportionately higher than 2003 due to 12 months of operations in 2004 compared to five months of operations in 2003.

Net Cash Deficiency Analysis

R&M's cash deficiency of $71 million in 2004 compared to a deficiency of $220 million in 2003. The increase in cash flow from operations to $59 million in 2004 from $34 million in 2003 was impacted by the same factors that affected net earnings. Net working capital decreased $68 million in 2004, compared to a decrease of $46 million in 2003. The decrease in 2004 was due primarily to an increase in accounts payable related to capital expenditures on the refinery modifications.

Cash used in investing activities was $198 million in 2004, compared to $300 million in 2003. Investing activities in 2004 were primarily related to costs associated with the refinery modification project. In 2003, investing activities were substantially all related to the acquisition of the Denver refinery and related assets on August 1 of that year.

Bridge Analysis of Net Cash Deficiency
($ millions)



Outlook

R&M estimates that it will spend approximately $260 million (approximately US$195 million) on new capital project work in 2005. Most of this investment will enable continuation of modifications that began at the Denver refinery during 2004. The project, which is expected to cost a total of approximately $360 million (approximately US$300 million), is expected to be substantially completed in early 2006.

R&M expects to spend an additional $29 million (US$24 million) by 2006 to meet existing obligations between the refinery and the United States Environmental Protection Agency and the State of Colorado. The expenditures, intended to improve environmental performance, are expected to be primarily capital.

The refinery runs a mixture of heavy and light crude oil feedstock from both Canadian and U.S. sources. In 2004, approximately 6% of R&M's crude slate came from Oil Sands. Suncor is currently assessing plans for potential additional refinery modifications post-2006 in order to have the potential to integrate up to an additional 30,000 bpd of Oil Sands crude oil. Cost estimates for this project are not yet available.

During the fourth quarter of 2005, scheduled maintenance is planned for pipeline and refinery equipment. During this estimated 42-day maintenance period, customer requirements are expected to be met from existing inventory and third-party purchases and exchanges.

During 2004, R&M was able to enter into firm sales commitments with new and existing customers to sell all of its excess refinery production. R&M also plans to improve overall profitability by seeking to optimize refining margins through a combination of branded and unbranded sales.

R&M's existing four-year contract with the local Paper, Allied-Industrial Chemical and Energy Workers International Union, which applies to hourly wage employees at the refinery, will expire in January 2006.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the R&M business include, but are not limited to, the following:

- Management expects continuing fluctuations in demand for refined products, margin and price volatility and market competitiveness, including potential new market entrants, will continue to impact the business.
- There are certain risks associated with the execution of the fuels desulphurization project, including ensuring construction and commissioning is completed in time to comply with June 1, 2006 legislative requirements. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period. As well, Suncor's U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for U.S. capital programs.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 53 under Forward-looking Statements. Refer to the Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

non gaap financial measures

Certain financial measures referred to in this MD&A are not prescribed by generally accepted accounting principles (GAAP). These non GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes cash flow from operations (dollars and per share amounts), return on capital employed (ROCE), and cash and total operating costs per barrel data because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Cash Flow from Operations per Common Share

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are an integral part of Suncor's Consolidated Financial Statements.

For the year ended December 31		**2004**	2003	2002
Cash flow from operations ($ millions)	A	**2 021**	2 079	1 440
Dividends paid on preferred securities ($ millions, pretax)	B	**9**	45	48
Weighted average number of common shares outstanding (millions of shares)	C	**453**	450	448
Cash flow from operations (per share)	A/C	**4.46**	4.62	3.22
Dividends paid on preferred securities (pretax, per share)	B/C	**0.02**	0.10	0.11
Cash flow from operations after deducting dividends paid on preferred securities (per share)	(A-B)/C	**4.44**	4.52	3.11

ROCE

For the year ended December 31 ($ millions, except ROCE)		**2004**	2003	2002
Adjusted net earnings				
Net earnings		**1 100**	1 075	749
Add: after-tax financing expenses (income)		**(10)**	(75)	72
	D	**1 090**	1 000	821
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**2 091**	2 671	3 143
Shareholders' equity		**4 355**	3 397	2 731
	E	**6 446**	6 068	5 874
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**2 159**	2 091	2 671
Shareholders' equity		**4 897**	4 355	3 397
	F	**7 056**	6 446	6 068
Average capital employed	(E+F)/2=G	**6 751**	6 257	5 971
Average capitalized costs related to major projects in progress (1)	H	**1 030**	817	345
ROCE (%)	D/(G-H)	**19.1**	18.4	14.6

(1) Prior to 2004, average capital employed was calculated using a simple average of opening and closing major projects in progress In 2004, the company has used a quarterly average.

Oil Sands Operating Costs – Base Operations

		2004 (1)		2003		2002	
		$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**871**		865		790	
Less: natural gas costs and inventory changes		**(142)**		(176)		(116)	
Accretion of asset retirement obligations		**21**		21		19	
Taxes other than income taxes		**28**		24		23	
Cash costs		**778**	**9.80**	734	9.25	716	9.55
Natural gas		**158**	**2.00**	169	2.15	119	1.55
Imported bitumen (net of other reported product purchases)		**13**	**0.15**	4	0.05	3	0.05
Cash operating costs – mining	A	**949**	**11.95**	907	11.45	838	11.15
Start-up costs		**26**		10		3	
Add: in-situ inventory changes		**2**		—		—	
Less: pre-start-up commissioning costs		**(4)**		(10)		(3)	
In-situ (Firebag) start-up costs	B	**24**	**0.30**	—	—	—	—
Total cash operating costs	A+B	**973**	**12.25**	907	11.45	838	11.15
Depreciation, depletion and amortization		**482**	**6.10**	458	5.80	458	6.10
Total operating costs		**1 455**	**18.35**	1 365	17.25	1 296	17.25
Production (thousands of barrels per day)		**217.0**		216.6		205.8	

Oil Sands Operating Costs – Firebag In-situ Bitumen Production

	2004 (1)	
	$ millions	$/barrel
Operating, selling and general expenses	**68**	
Less: natural gas costs and inventory changes	**(39)**	
Accretion of asset retirement obligations	—	
Taxes other than income taxes	—	
Cash costs	**29**	**8.30**
Natural gas	**39**	**11.20**
Cash operating costs	**68**	**19.50**
Depreciation, depletion and amortization	**21**	**6.00**
Total operating costs	**89**	**25.50**
Production (thousands of barrels per day)	**12.7**	

(1) Production in the base operations for the year ended December 31, 2004 includes upgraded Firebag in-situ volumes of 5,900 bpd produced in the first quarter of 2004 during the Firebag start-up period.

forward-looking statements

This Management's Discussion and Analysis contains certain Forward-looking Statements that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are Forward-looking Statements. Some of the Forward-looking Statements may be identified by words like "expects," "anticipates," "estimates," "plans," "intends," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "proposed," "target," "objective" and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its Forward-looking Statements and readers are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors that could influence actual results include but are not limited to: changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products, commodity prices and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the Firebag in-situ development and Voyageur) and regulatory projects (for example, the clean fuels refinery modifications projects in Suncor's downstream businesses); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint-venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; the uncertainties resulting from the January 2005 fire at the Oil Sands facility and other uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; changes in environmental and other regulations; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as the January 2005 fire, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. The foregoing important factors are not exhaustive. Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's Annual Information Form/Form 40-F on file with Canadian securities commissions and the United States Securities and Exchange Commission (SEC). Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

management's statement of responsibility for financial reporting

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. on pages 58 to 92 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

We, as Suncor Energy Inc.'s Chief Executive Officer and Chief Financial Officer, will certify Suncor's annual disclosure document filed with the United States Securities and Exchange Commission (Form 40-F) as required by the United States Sarbanes-Oxley Act.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management as summarized on pages 58 to 61. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of all aspects of the company's operations.

The company retains independent petroleum consultants, Gilbert Laustsen Jung Associates Ltd., to conduct independent evaluations of the company's oil and gas reserves.

The Audit Committee of the Board of Directors, currently composed of five independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditors to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent petroleum consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves estimates, and recommend their approval to the Board of Directors. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors.

Rich George

Richard L. George
President and
Chief Executive Officer

J K Alley

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

February 23, 2005

The following report is provided by management in respect of the company's internal control over financial reporting (as defined in Rule 13a-15(f) under the U.S. Securities Exchange Act of 1934):

management's report on internal control over financial reporting

1. Management is responsible for establishing and maintaining adequate internal control over the company's financial reporting.
2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.
3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2004, and has concluded that such internal control over financial reporting was effective as at that date. Additionally, based on our assessment, we determined that there were no material weaknesses in internal control over financial reporting as of December 31, 2004.
4. PricewaterhouseCoopers LLP, who has audited the company's consolidated financial statements for the year ended December 31, 2004, has also audited management's assessment of the effectiveness of the company's internal control over financial reporting as at December 31, 2004 as stated in their report which appears herein.

Rich George

Richard L. George
President and
Chief Executive Officer

February 23, 2005

J K Alley

J. Kenneth Alley
Senior Vice President and
Chief Financial Officer

auditors' report

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have audited the accompanying Consolidated Balance Sheets of Suncor Energy Inc. (the company) as at December 31, 2004 and 2003 and the related Consolidated Statements of Earnings, Cash Flows and Changes in Shareholders' Equity for each of the years in the three-year period ended December 31, 2004. We have also audited the effectiveness of the company's internal control over financial reporting as at December 31, 2004, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and management's assessment thereof included in the accompanying Management's Report on Internal Control over Financial Reporting. The company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these financial statements, an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audits.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

We conducted our audits of the company's financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We conducted our audit of the effectiveness of the company's internal control over financial reporting and management's assessment thereof in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles. Also, in our opinion, management's assessment that the company maintained effective internal control over financial reporting as at December 31, 2004 is fairly stated, in all material respects, based on criteria established in Internal Control – Integrated Framework issued by the COSO. Furthermore, in our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2004 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 23, 2005

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA – U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the company's financial statements, such as the change described in Note 1 to the consolidated financial statements. Our report to the shareholders dated February 23, 2005 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta, Canada

February 23, 2005

summary of significant accounting policies

Suncor Energy Inc. is a Canadian integrated energy company comprised of four operating segments: Oil Sands, Natural Gas, Energy Marketing and Refining – Canada, and Refining and Marketing – U.S.A.

Oil Sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands in the Athabasca region of northeastern Alberta, and the marketing of these products substantially in Canada and the United States.

Natural Gas includes the exploration, acquisition, development, production, transportation and marketing of natural gas and crude oil in Canada and the United States.

Energy Marketing and Refining – Canada includes the manufacture, transportation and marketing of petroleum and petrochemical products, primarily in Ontario and Quebec. Petrochemical products are also sold in the United States and Europe.

Refining and Marketing – U.S.A. includes the manufacture, transportation and marketing of petroleum products, primarily in Colorado.

The significant accounting policies of the company are summarized below:

(a) Principles of Consolidation and the Preparation of Financial Statements
These consolidated financial statements are prepared and reported in Canadian dollars in accordance with generally accepted accounting principles (GAAP) in Canada, which differ in some respects from GAAP in the United States. These differences are quantified and explained in note 19.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of its joint-ventures.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Certain prior period comparative figures have also been reclassified to conform to the current period presentation.

(b) Cash Equivalents and Investments
Cash equivalents consist primarily of term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less. Investments with maturities greater than three months and up to one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments. Cash equivalents and short-term investments are stated at cost, which approximates market value.

(c) Revenues
Crude oil sales from upstream operations (Oil Sands and Natural Gas) to downstream operations (Energy Marketing and Refining – Canada and Refining and Marketing – U.S.A.) are based on actual product shipments. On consolidation, revenues and purchases related to these sales transactions are eliminated from operating revenues and purchases of crude oil and products.

The company also uses a portion of its natural gas production for internal consumption at its oil sands plant and Sarnia refinery. On consolidation, revenues from these sales are eliminated from operating revenues, crude oil and products purchases, and operating, selling and general expenses.

Revenues associated with sales of crude oil, natural gas, petroleum and petrochemical products and all other items not eliminated on consolidation are recorded when title passes to the customer and delivery has taken place. Revenues from oil and natural gas production from properties in which the company has an interest with other producers are recognized on the basis of the company's net working interest. Revenues associated with multi-element arrangements are recognized on a straight-line basis over the term of associated services.

(d) Property, Plant and Equipment and Intangible Assets
Cost
Property, plant and equipment and intangible assets are recorded at cost.

Expenditures to acquire and develop Oil Sands mining properties are capitalized. Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are also capitalized.

The company follows the successful efforts method of accounting for its conventional natural gas and in-situ oil sands operations. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are initially capitalized. If it is determined that a specific well does not contain proved reserves, the related capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time. Related land costs are expensed through the amortization of unproved properties as covered under the Natural Gas section of the depreciation, depletion and amortization policy below.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs and the costs of acquiring or constructing support facilities and equipment, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed as operating costs.

Costs incurred after the inception of operations are expensed.

Interest Capitalization

Interest costs relating to major capital projects in progress and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use.

Leases

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

Gains and losses on the sale and leaseback of assets recorded as capital leases are deferred and amortized to earnings in proportion to the amortization of leased assets.

Depreciation, Depletion and Amortization

OIL SANDS Property, plant and equipment are depreciated over their useful lives on a straight-line basis, commencing when the assets are placed into service. Mine and mobile equipment is depreciated over periods ranging from three to 20 years and plant and other property and equipment, including leases in service, primarily over four to 40 years. Capitalized costs related to the in-progress phase of projects are not depreciated until the facilities are substantially complete and ready for their intended productive use.

NATURAL GAS Acquisition costs of unproved properties that are individually significant are evaluated for impairment by management. Impairment of unproved properties that are not individually significant is provided for through amortization over the average projected holding period for that portion of acquisition costs not expected to become producing. The average projected holding period of five years is based on historical experience.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Gas plants, support facilities and equipment are depreciated on a straight-line basis over their useful lives, which average 12 years.

DOWNSTREAM OPERATIONS (INCLUDING ENERGY MARKETING AND REFINING – CANADA AND REFINING AND MARKETING – U.S.A.) Depreciation of property, plant and equipment is provided on a straight-line basis over the useful lives of assets. The Sarnia and Denver refineries and additions thereto are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and pipeline facilities and other equipment over three to 40 years. Intangible assets with determinable useful lives are amortized over a maximum period of four years. The amortization of intangible assets is included within depreciation expense in the Consolidated Statements of Earnings.

Asset Retirement Obligations

On January 1, 2004, the company retroactively adopted the new Canadian accounting standard related to "Asset Retirement Obligations" (ARO). Under the new standard, a liability is recognized for the future retirement obligations associated with the company's property, plant and equipment. The fair value of the ARO is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation.

Impairment
Property, plant and equipment, including capitalized asset retirement costs are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less future income taxes, may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to earnings.

Disposals
Gains or losses on disposals of non-oil and gas property, plant and equipment are recognized in earnings. For oil and gas property, plant and equipment, gains or losses are recognized in earnings for significant disposals or disposal of an entire property. However, the acquisition cost of a subsequently surrendered or abandoned unproved property that is not individually significant, or a partial abandonment of a proved property, is charged to accumulated depreciation, depletion or amortization.

(e) Deferred Charges and Other
Deferred charges and other are primarily comprised of deferred overburden removal costs, deferred maintenance shutdown costs and deferred financing costs.

Overburden removal may precede mining of the oil sands deposit by as much as two years. Accordingly, the company employs a deferral method of accounting for overburden removal costs where all such costs are initially recorded as a deferred charge (see note 4), rather than expensing overburden removal costs as incurred. These deferred charges are allocated to the mining activity in the year on a last-in, first-out (LIFO) basis using stripping ratios based on a life-of-mine approach for each mine pit whereby all of the overburden to be removed is related to all of the oil sands proved and probable ore reserves. Amortization of deferred overburden removal cost is reported as part of the depreciation, depletion and amortization expense in the Consolidated Statements of Earnings. Stripping ratios are regularly reviewed to reflect changes in operating experience and other factors.

The cost of major maintenance shutdowns is deferred and amortized on a straight-line basis over the period to the next shutdown, which varies from three to seven years. Normal maintenance and repair costs are charged to expense as incurred.

Financing costs related to the issuance of long-term debt are amortized over the term of the related debt.

(f) Employee Future Benefits
The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued ratably from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based on a year-end market rate of interest for high quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

(g) Inventories
Inventories of crude oil and refined products are valued at the lower of cost (using the LIFO method) and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value.

Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

(h) Derivative Financial Instruments
The company periodically enters into derivative financial instrument commodity contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying commodity indices. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage exposure to interest rate fluctuations.

These derivative contracts are initiated within the guidelines of the company's risk management policies, which require stringent authorities for approval and commitment of contracts, designation of the contracts by management as hedges of the related transactions, and monitoring of the effectiveness of such contracts in reducing the related risks. Contract maturities are consistent with the settlement dates of the related hedged transactions.

Derivative contracts accounted for as hedges are not recognized in the Consolidated Balance Sheets. Gains or losses on these contracts, including realized gains and losses on hedging derivative contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized. Gains or

losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Canadian Accounting Guideline 13 (AcG 13), "Hedging Relationships," is applicable to the company's hedging relationships in 2004 and subsequent fiscal years. AcG 13 specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, as well as the discontinuance of hedge accounting. The Guideline does not specify hedge accounting methods. The company believes that its hedging documentation and tests of effectiveness are prepared in accordance with the provisions of AcG-13.

The company also uses energy derivatives, including physical and financial swaps, forwards and options, to gain market information and to earn trading revenues. These energy marketing and trading activities are accounted for at fair value.

(i) Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. Other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

The company's Refining and Marketing – U.S.A. operations are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in cumulative foreign exchange adjustments in the Consolidated Statements of Changes in Shareholders' Equity.

(j) Stock-based Compensation Plans

Under the company's common share option programs (see note 13), common share options are granted to executives, employees and non-employee directors.

Compensation expense is recorded in the Consolidated Statements of Earnings as operating, selling and general expense for all common share options granted to employees and non-employee directors on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. The expense is based on the fair values of the option at the time of grant and is recognized in the Consolidated Statements of Earnings over the estimated vesting periods of the respective options. For common share options granted prior to January 1, 2003 ("pre-2003 options"), compensation expense is not recognized in the Consolidated Statement of Earnings. The company continues to disclose the pro forma earnings impact of related stock-based compensation expense for pre-2003 options. Consideration paid to the company on exercise of options is credited to share capital.

Stock-based compensation awards that are to be settled in cash are measured using the fair value based method of accounting.

(k) Transportation Costs

Transportation costs billed to customers are classified as revenues with the related transportation costs classified as transportation and other costs in the Consolidated Statements of Earnings.

(l) Recently Issued Canadian Accounting Standards

Variable Interest Entities

In 2003, Canadian Accounting Guideline 15 (AcG 15), "Consolidation of Variable Interest Entities" (VIEs), was issued. Effective January 1, 2005, AcG 15 requires consolidation of a VIE where the company will absorb a majority of a VIE's losses, receive a majority of its returns, or both. The company will be required to consolidate the VIE related to the sale of equipment as described in note 11(c). The company does not expect a significant impact on net earnings upon consolidation of the equipment VIE. The impact on the balance sheet will be an increase to property, plant and equipment of $14 million, an increase to inventory of $8 million, and an increase to long-term debt of $22 million. The company's accounts receivable securitization program described in note 11(c), as currently structured, does not meet the AcG 15 criteria for consolidation by Suncor.

Liabilities and Equity

In 2003, the Canadian Accounting Standards Board approved an amendment to its Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" requiring certain obligations that must or could be settled with an entity's own equity instruments to be presented as liabilities. The amendment, effective for the company's 2005 fiscal year and applied on a retroactive basis, will affect the company's current presentation of preferred securities as equity (see note 12). The reclassification of the preferred securities from equity to long-term debt is expected to increase property, plant and equipment by $37 million, and increase depreciation, depletion and amortization by $1 million.

consolidated statements of earnings

For the years ended December 31 ($ millions)	**2004**	2003	2002
Revenues			
Operating revenues (notes 7, 17 and 18)	**8 226**	6 289	4 883
Energy marketing and trading activities (note 7c)	**392**	276	147
Interest	**3**	6	2
	8 621	6 571	5 032
Expenses			
Purchases of crude oil and products	**2 867**	1 686	1 156
Operating, selling and general	**1 769**	1 478	1 274
Energy marketing and trading activities (note 7)	**373**	279	142
Transportation and other costs	**132**	135	128
Depreciation, depletion and amortization	**717**	618	595
Accretion of asset retirement obligations	**26**	25	25
Exploration (note 18)	**55**	51	26
Royalties (note 5)	**531**	139	98
Taxes other than income taxes (note 18)	**496**	426	374
(Gain) on disposal of assets	**(16)**	(17)	(2)
(Gain) on sale of retail natural gas marketing business (note 18)	**—**	—	(38)
Project start-up costs	**26**	16	3
Financing expenses (income) (note 15)	**9**	(66)	124
	6 985	4 770	3 905
Earnings Before Income Taxes	**1 636**	1 801	1 127
Provision for income taxes (note 10)			
Current	**69**	38	74
Future	**467**	688	304
	536	726	378
Net Earnings	**1 100**	1 075	749
Dividends on preferred securities, net of tax (note 12)	**(6)**	(27)	(28)
Revaluation of US$ preferred securities, net of tax	**(6)**	37	1
Net earnings attributable to common shareholders	**1 088**	1 085	722
Per Common Share (dollars) (note 14)			
Net earnings attributable to common shareholders			
Basic	**2.40**	2.41	1.61
Diluted	**2.36**	2.24	1.58
Cash dividends	**0.23**	0.1925	0.17

See accompanying Summary of Significant Accounting Policies and Notes.

consolidated balance sheets

As at December 31 ($ millions)	2004	2003
Assets		
Current assets		
Cash and cash equivalents	**88**	388
Accounts receivable (notes 11c and 18)	**627**	505
Inventories (note 16)	**423**	371
Future income taxes (note 10)	**57**	15
Total current assets	**1 195**	1 279
Property, plant and equipment, net (note 3)	**10 289**	8 936
Deferred charges and other (note 4)	**320**	286
Total assets	**11 804**	10 501
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**30**	31
Accounts payable and accrued liabilities (notes 8 and 9)	**1 306**	970
Income taxes payable	**32**	9
Taxes other than income taxes	**41**	49
Future income taxes (note 10)	**—**	1
Total current liabilities	**1 409**	1 060
Long-term debt (note 6)	**2 217**	2 448
Accrued liabilities and other (notes 8 and 9)	**749**	616
Future income taxes (note 10)	**2 532**	2 022
Total liabilities	**6 907**	6 146
Commitments and contingencies (note 11)		
Shareholders' equity		
Preferred securities (note 12)	**—**	476
Share capital (note 13)	**651**	604
Contributed surplus (note 13)	**32**	7
Cumulative foreign currency translation	**(55)**	(26)
Retained earnings	**4 269**	3 294
Total shareholders' equity	**4 897**	4 355
Total liabilities and shareholders' equity	**11 804**	10 501

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:

Richard L. George
Director

John T. Ferguson
Director

February 23, 2005

consolidated statements of cash flows

For the years ended December 31 ($ millions)	**2004**	2003	2002
Operating Activities			
Cash flow from operations [(a)]	**2 021**	2 079	1 440
Decrease (increase) in operating working capital			
(net of effects of acquisition of Denver refinery and related assets)			
Accounts receivable	**(121)**	(105)	(97)
Inventories	**(51)**	(19)	(8)
Accounts payable and accrued liabilities	**337**	258	44
Taxes payable	**16**	5	77
Cash flow from operating activities	**2 202**	2 218	1 456
Cash Used in Investing Activities [(a)]	**(1 824)**	(1 702)	(861)
Net Cash Surplus Before Financing Activities	**378**	516	595
Financing Activities			
Increase (decrease) in short-term debt	**(1)**	31	(31)
Proceeds from issuance of long-term debt	**—**	651	797
Net decrease in other long-term debt	**(142)**	(716)	(1 245)
Redemption of preferred securities (note 12)	**(493)**	—	—
Issuance of common shares under stock option plans	**41**	20	19
Dividends paid on preferred securities	**(9)**	(45)	(48)
Dividends paid on common shares	**(97)**	(81)	(73)
Deferred revenue	**26**	—	—
Cash flow used in financing activities	**(675)**	(140)	(581)
Increase (Decrease) in Cash and Cash Equivalents	**(297)**	376	14
Effect of Foreign Exchange on Cash and Cash Equivalents	**(3)**	(3)	—
Cash and Cash Equivalents at Beginning of Year	**388**	15	1
Cash and Cash Equivalents at End of Year	**88**	388	15

(a) See Schedules of Segmented Data on pages 68 and 69.

See accompanying Summary of Significant Accounting Policies and Notes.

consolidated statements of changes in shareholders' equity

For the years ended December 31 ($ millions)	Preferred Securities	Share Capital	Contributed Surplus	Cumulative Foreign Currency Translation	Retained Earnings
At December 31, 2001, as previously reported	525	555	—	—	1 700
Retroactive adjustment for change in accounting policy, net of tax (note 1)	—	—	—	—	(49)
At December 31, 2001, as restated	525	555	—	—	1 651
Net earnings	—	—	—	—	749
Dividends paid on preferred securities, net of tax	—	—	—	—	(28)
Dividends paid on common shares	—	—	—	—	(73)
Issued for cash under stock option plans	—	19	—	—	—
Issued under dividend reinvestment plan	—	4	—	—	(4)
Revaluation of US$ preferred securities	(2)	—	—	—	1
At December 31, 2002, as restated	523	578	—	—	2 296
Net earnings	—	—	—	—	1 075
Dividends paid on preferred securities, net of tax	—	—	—	—	(27)
Dividends paid on common shares	—	—	—	—	(81)
Issued for cash under stock option plans	—	20	—	—	—
Issued under dividend reinvestment plan	—	6	—	—	(6)
Stock-based compensation expense	—	—	7	—	—
Foreign currency translation adjustment	—	—	—	(26)	—
Revaluation of US$ preferred securities	(47)	—	—	—	37
At December 31, 2003, as restated	**476**	**604**	**7**	**(26)**	**3 294**
Net earnings	—	—	—	—	**1 100**
Dividends paid on preferred securities, net of tax	—	—	—	—	**(6)**
Dividends paid on common shares	—	—	—	—	**(97)**
Issued for cash under stock option plans	—	**41**	—	—	—
Issued under dividend reinvestment plan	—	**6**	—	—	**(6)**
Stock-based compensation expense	—	—	**25**	—	—
Foreign currency translation adjustment	—	—	—	**(29)**	—
Revaluation of US$ preferred securities	**7**	—	—	—	**(6)**
Reclassification of issue costs for preferred securities	**10**	—	—	—	**(10)**
Redemption of preferred securities (note 12)	**(493)**	—	—	—	—
At December 31, 2004	—	**651**	**32**	**(55)**	**4 269**

See accompanying Summary of Significant Accounting Policies and Notes.

schedules of segmented data[a]

For the years ended December 31 ($ millions)	**2004**	Oil Sands 2003	2002	**2004**	Natural Gas 2003	2002	**2004**	Energy Marketing and Refining – Canada 2003	2002
EARNINGS									
Revenues [b]									
Operating revenues	**3 171**	2 676	2 241	**499**	436	279	**3 060**	2 660	2 361
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**400**	276	147
Intersegment revenues [c]	**425**	385	375	**68**	76	60	**—**	—	—
Interest	**—**	—	—	**—**	—	—	**—**	—	—
	3 596	3 061	2 616	**567**	512	339	**3 460**	2 936	2 508
Expenses									
Purchases of crude oil and products	**75**	12	7	**—**	—	16	**2 115**	1 797	1 564
Operating, selling and general	**939**	865	790	**100**	73	67	**418**	359	352
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**381**	279	142
Transportation and other costs	**88**	101	104	**21**	24	24	**3**	3	—
Depreciation, depletion and amortization	**503**	458	458	**115**	91	75	**69**	59	60
Accretion of asset retirement obligations	**21**	21	19	**4**	3	4	**1**	1	2
Exploration	**17**	11	9	**38**	40	17	**—**	—	—
Royalties (note 5)	**407**	33	33	**124**	106	65	**—**	—	—
Taxes other than income taxes	**28**	24	23	**2**	3	2	**352**	342	348
(Gain) loss on disposal of assets	**4**	(1)	2	**(19)**	(12)	(4)	**(2)**	(4)	—
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	—	(38)
Project start-up costs	**26**	10	3	**—**	—	—	**—**	—	—
Financing expenses (income)	**—**	—	—	**—**	—	—	**—**	—	—
	2 108	1 534	1 448	**385**	328	266	**3 337**	2 836	2 430
Earnings (loss) before income taxes	**1 488**	1 527	1 168	**182**	184	73	**123**	100	78
Provision for income taxes	**(493)**	(639)	(386)	**(67)**	(64)	(39)	**(43)**	(47)	(17)
Net earnings (loss)	**995**	888	782	**115**	120	34	**80**	53	61
As at December 31									
TOTAL ASSETS	**9 032**	7 934	7 186	**965**	763	793	**1 321**	1 080	978

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

(b) There were no customers that represented 10% or more of the company's 2004 or 2003 consolidated revenues. (2002 – one customer represented 10% or more ($641 million)).

(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

See accompanying Summary of Significant Accounting Policies and Notes.

schedules of segmented data[a] (continued)

For the years ended December 31 ($ millions)	Refining and Marketing U.S.A. 2004	2003	2002	Corporate and Eliminations 2004	2003	2002	Total 2004	2003	2002
EARNINGS									
Revenues [b]									
Operating revenues	**1 494**	515	—	**2**	2	2	**8 226**	6 289	4 883
Energy marketing and trading activities	**—**	—	—	**(8)**	—	—	**392**	276	147
Intersegment revenues [c]	**—**	—	—	**(493)**	(461)	(435)	**—**	—	—
Interest	**1**	—	—	**2**	6	2	**3**	6	2
	1 495	515	—	**(497)**	(453)	(431)	**8 621**	6 571	5 032
Expenses									
Purchases of crude oil and products	**1 171**	340	—	**(494)**	(463)	(431)	**2 867**	1 686	1 156
Operating, selling and general	**124**	68	—	**188**	113	65	**1 769**	1 478	1 274
Energy marketing and trading activities	**—**	—	—	**(8)**	—	—	**373**	279	142
Transportation and other costs	**20**	7	—	**—**	—	—	**132**	135	128
Depreciation, depletion and amortization	**22**	6	—	**8**	4	2	**717**	618	595
Accretion of asset retirement obligations	**—**	—	—	**—**	—	—	**26**	25	25
Exploration	**—**	—	—	**—**	—	—	**55**	51	26
Royalties (note 5)	**—**	—	—	**—**	—	—	**531**	139	98
Taxes other than income taxes	**114**	57	—	**—**	—	1	**496**	426	374
(Gain) loss on disposal of assets	**1**	—	—	**—**	—	—	**(16)**	(17)	(2)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	—	(38)
Project start-up costs	**—**	6	—	**—**	—	—	**26**	16	3
Financing expenses (income)	**—**	—	—	**9**	(66)	124	**9**	(66)	124
	1 452	484	—	**(297)**	(412)	(239)	**6 985**	4 770	3 905
Earnings (loss) before income taxes	**43**	31	—	**(200)**	(41)	(192)	**1 636**	1 801	1 127
Provision for income taxes	**(9)**	(13)	—	**76**	37	64	**(536)**	(726)	(378)
Net earnings (loss)	**34**	18	—	**(124)**	(4)	(128)	**1 100**	1 075	749
As at December 31 **TOTAL ASSETS**	**518**	442	—	**(32)**	282	54	**11 804**	10 501	9 011

schedules of segmented data[a] (continued)

For the years ended December 31 ($ millions)	Oil Sands 2004	Oil Sands 2003	Oil Sands 2002	Natural Gas 2004	Natural Gas 2003	Natural Gas 2002	Energy Marketing and Refining – Canada 2004	Energy Marketing and Refining – Canada 2003	Energy Marketing and Refining – Canada 2002
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**995**	888	782	**115**	120	34	**80**	53	61
Exploration expenses	**—**	—	—	**38**	40	17	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**503**	458	458	**115**	91	75	**69**	59	60
Income taxes	**493**	639	386	**67**	64	39	**43**	47	17
(Gain) loss on disposal of assets	**4**	(1)	2	**(19)**	(12)	(4)	**(2)**	(4)	(38)
Stock-based compensation expense	**—**	—	—	**—**	—	—	**—**	—	—
Other	**(29)**	4	15	**4**	(5)	4	**(3)**	10	11
Overburden removal outlays	**(222)**	(175)	(160)	**—**	—	—	**—**	—	—
Increase (decrease) in deferred credits and other	**8**	(10)	(8)	**(1)**	—	(1)	**1**	(1)	1
Total cash flow from (used in) operations	**1 752**	1 803	1 475	**319**	298	164	**188**	164	112
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)	**71**	51	(116)	**(1)**	11	22	**50**	—	(15)
Total cash from (used in) operating activities	**1 823**	1 854	1 359	**318**	309	186	**238**	164	97
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(1 118)**	(948)	(617)	**(279)**	(183)	(163)	**(228)**	(122)	(60)
Acquisition of Denver refinery and related assets	**—**	—	—	**—**	—	—	**—**	—	—
Deferred maintenance shutdown expenditures	**(4)**	(100)	(9)	**(1)**	—	—	**(20)**	(17)	(18)
Deferred outlays and other investments	**(9)**	(10)	(4)	**—**	—	—	**(14)**	(2)	(18)
Proceeds from disposals	**45**	3	—	**29**	17	5	**3**	6	62
Total cash (used in) investing activities	**(1 086)**	(1 055)	(630)	**(251)**	(166)	(158)	**(259)**	(135)	(34)
Net cash surplus (deficiency) before financing activities	**737**	799	729	**67**	143	28	**(21)**	29	63

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and Notes.

For the years ended December 31 ($ millions)	Refining and Marketing U.S.A. 2004	2003	2002	Corporate and Eliminations 2004	2003	2002	Total 2004	2003	2002
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**34**	18	—	**(124)**	(4)	(128)	**1 100**	1 075	749
Exploration expenses	**—**	—	—	**—**	—	—	**38**	40	17
Non-cash items included in earnings									
Depreciation, depletion and amortization	**22**	6	—	**8**	4	2	**717**	618	595
Income taxes	**9**	13	—	**(145)**	(75)	(138)	**467**	688	304
(Gain) loss on disposal of assets	**1**	—	—	**—**	—	—	**(16)**	(17)	(40)
Stock-based compensation expense	**—**	—	—	**25**	7	—	**25**	7	—
Other	**(8)**	(2)	—	**(78)**	(163)	(3)	**(114)**	(156)	27
Overburden removal outlays	**—**	—	—	**—**	—	—	**(222)**	(175)	(160)
Increase (decrease) in deferred credits and other	**1**	(1)	—	**17**	11	(44)	**26**	(1)	(52)
Total cash flow from (used in) operations	**59**	34	—	**(297)**	(220)	(311)	**2 021**	2 079	1 440
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)	**68**	46	—	**(7)**	31	125	**181**	139	16
Total cash from (used in) operating activities	**127**	80	—	**(304)**	(189)	(186)	**2 202**	2 218	1 456
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(190)**	(31)	—	**(31)**	(32)	(37)	**(1 846)**	(1 316)	(877)
Acquisition of Denver refinery and related assets	**—**	(272)	—	**—**	—	—	**—**	(272)	—
Deferred maintenance shutdown expenditures	**(7)**	—	—	**—**	—	—	**(32)**	(117)	(27)
Deferred outlays and other investments	**(1)**	3	—	**1**	(14)	(2)	**(23)**	(23)	(24)
Proceeds from disposals	**—**	—	—	**—**	—	—	**77**	26	67
Total cash (used in) investing activities	**(198)**	(300)	—	**(30)**	(46)	(39)	**(1 824)**	(1 702)	(861)
Net cash surplus (deficiency) before financing activities	**(71)**	(220)	—	**(334)**	(235)	(225)	**378**	516	595

1. CHANGE IN ACCOUNTING POLICY

On January 1, 2004, the company retroactively adopted a new accounting policy for asset retirement obligations (see Summary of Significant Accounting Policies). The 2003 and estimated 2004 impact of adopting the new Canadian accounting standard compared to the previous standard is:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	**2004**	2003
Property, plant and equipment	**284**	211
Future income tax assets	**33**	37
Total assets	**317**	248
Accounts payable and accrued liabilities	**—**	(2)
Accrued liabilities and other	**382**	320
Retained earnings	**(65)**	(70)
Total liabilities and shareholders' equity	**317**	248

Change in Consolidated Statements of Earnings

($ millions, increase/(decrease))	**2004**	2003	2002
Depreciation, depletion and amortization	**9**	7	10
Accretion of asset retirement obligations	**26**	25	25
Operating, selling and general expenses	**(43)**	(29)	(18)
Future income taxes	**3**	6	(5)
Net earnings	**5**	(9)	(12)
Per common share – basic (dollars)	**0.01**	(0.02)	(0.03)
Per common share – diluted (dollars)	**0.01**	(0.02)	(0.03)

See note 8 for a reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation.

2. ACQUISITION OF REFINERY AND RELATED ASSETS

On August 1, 2003, the company acquired a Denver refinery, 43 retail stations and associated storage, pipeline and distribution facilities, and inventory from ConocoPhillips for cash consideration of $272 million. The purchase price was determined through a competitive bid process. The results of operations for these assets have been included in the consolidated financial statements from the date of acquisition.

The acquisition was accounted for by the purchase method of accounting. The allocation of fair value to the assets acquired and liabilities assumed was:

($ millions)	
Property, plant and equipment, and intangible assets	242
Inventory	88
Other assets	9
Total assets acquired	339
Liabilities assumed	(67)
Net assets acquired	272

Suncor recorded an environmental liability of $9 million at the acquisition date for the estimated costs of environmental clean-up work currently under way. A $9 million receivable was also recorded as ConocoPhillips agreed to indemnify Suncor for these costs. The recorded liability is part of an agreement between Suncor and ConocoPhillips whereby Suncor will be indemnified for any reclamation work identified prior to closing for a period up to 10 years from acquisition date, and up to $30 million. Additional costs ordered by a governmental agency are subject to indemnification from ConocoPhillips on a rolling 10-year limitation period from the date the contamination is discovered by Suncor. There is no time or dollar limit for any third-party claims against Suncor for which ConocoPhillips is liable.

Additionally, a $39 million liability was recorded at acquisition for environmental work required pursuant to a consent decree between ConocoPhillips, the Colorado Department of Public Health and the Environment and the United States Environmental Protection Agency.

For segmented reporting purposes, the results of the new Denver-based operations since the date of acquisition are reported in a new operating segment (Refining and Marketing – U.S.A.) in the accompanying Schedules of Segmented Data.

3. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2004 Cost	2004 Accumulated Provision	2003 Cost	2003 Accumulated Provision
Oil Sands				
Plant	**5 156**	**929**	4 721	828
Mine and mobile equipment	**1 313**	**480**	1 267	426
In-situ properties	**1 267**	**26**	867	—
Pipeline	**101**	**48**	100	46
Capital leases	**29**	**25**	130	18
Major projects in progress	**1 486**	**—**	1 232	—
Asset retirement cost	**325**	**71**	267	63
	9 677	**1 579**	8 584	1 381
Natural Gas				
Proved properties	**1 396**	**653**	1 206	552
Unproved properties	**124**	**18**	114	38
Other support facilities and equipment	**18**	**13**	18	12
Asset retirement cost	**27**	**3**	4	2
	1 565	**687**	1 342	604
Energy Marketing and Refining – Canada				
Refinery	**875**	**468**	874	443
Marketing	**525**	**248**	494	239
Major projects in progress	**171**	**—**	—	—
Asset retirement cost	**11**	**5**	10	5
	1 582	**721**	1 378	687
Refining and Marketing – U.S.A.				
Refinery and intangible assets	**175**	**11**	165	2
Marketing	**38**	**2**	39	1
Pipeline	**25**	**1**	27	—
Major projects in progress	**128**	**—**	—	—
	366	**14**	231	3
Corporate	**118**	**18**	86	10
	13 308	**3 019**	11 621	2 685
Net property, plant and equipment		**10 289**		8 936

4. DEFERRED CHARGES AND OTHER

($ millions)	2004	2003
Oil Sands overburden removal costs (see below)	**67**	51
Deferred maintenance shutdown costs	**129**	137
Deferred financing costs	**25**	26
Other	**99**	72
Total deferred charges and other	**320**	286
Oil Sands overburden removal costs		
Balance – beginning of year	**51**	68
Outlays during the year	**222**	175
Depreciation on equipment during year	**19**	16
	292	259
Amortization during year	**(225)**	(208)
Balance – end of year	**67**	51

5. ROYALTIES

Crown royalties in effect for each Oil Sands project require payments to the Government of Alberta, based on annual gross revenues less related transportation costs (R) less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R. During 2004, the Alberta government confirmed it would modify Suncor's royalty treatment because it does not recognize the company's Firebag in-situ facility as an expansion to the company's existing base mining and upgrading operations. Accordingly, for Alberta Crown royalty purposes, Suncor's Oil Sands operations are considered as two separate projects: Suncor's base Oil Sands mining and associated upgrading operations and Suncor's Firebag in-situ oil sands project. On the basis of this classification, Suncor provided for Alberta Crown royalty obligations of $407 million in 2004 (2003 and 2002 – $33 million).

In July 2004, Suncor issued a statement of claim against the Province of Alberta, seeking, among other things, to overturn the Crown's decision on the royalty treatment of Firebag. The Crown has issued a statement of defence. Should the company be successful in its claim, any recoveries would be recognized in the period they are realized.

6. LONG-TERM DEBT

($ millions)	2004	2003
Fixed-term debt, redeemable at the option of the company		
5.95% Notes, denominated in U.S. dollars, due in 2034 (a)	**602**	646
7.15% Notes, denominated in U.S. dollars, due in 2032	**602**	646
6.70% Series 2 Medium Term Notes, due in 2011 (b)	**500**	500
6.80% Medium Term Notes, due in 2007 (b)	**250**	250
6.10% Medium Term Notes, due in 2007 (b)	**150**	150
7.40% Debentures, Series C, repaid in 2004	**—**	125
	2 104	2 317
Revolving-term debt, with interest at variable rates (see Credit Facilities)		
Commercial paper (interest at December 31, 2004 – 2.3%) (c)	**89**	—
Total unsecured long-term debt	**2 193**	2 317
Secured long-term debt with interest rates averaging 5.4% (2003 – 5.6%)	**5**	4
Capital leases (d), (e)	**19**	127
Total long-term debt	**2 217**	2 448

(a) In 2003, the company issued 5.95% Notes with a principal amount of US$500 million (Cdn$ equivalent of $651 million).

(b) The company has entered into various interest rate swap transactions that are outstanding at December 31, 2004. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of Swap Transaction	Principal Swapped ($ millions)	Swap Maturity	2004 Effective Interest Rate
Swap of 6.10% Medium Term Notes to floating rates	150	2007	3.6%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.3%
Swap of 6.70% Medium Term Notes to floating rates	200	2011	3.5%

(c) The company is authorized to issue commercial paper to a maximum of $900 million having a term not to exceed 364 days. Commercial paper is supported by unutilized credit facilities.

(d) Obligations under capital leases are as follows:

($ millions)	**2004**	2003
Energy services assets lease with interest at 6.82%, repaid in 2004	**—**	101
Other equipment leases with interest rates between prime plus 0.5% and 12.4% and maturity dates ranging from 2008 to 2029	**19**	26
	19	127

(e) Future minimum amounts payable under capital leases and other long-term debt are as follows:

($ millions)	Capital Leases	Other Long-term Debt
2005	3	90
2006	3	1
2007	3	401
2008	3	—
2009	3	—
Later years	24	1 706
Total minimum payments	39	2 198
Less amount representing imputed interest	20	
Present value of obligation under capital leases	19	

Long-term Debt (per cent)	**2004**	2003
Variable rate	**31**	25
Fixed rate	**69**	75

Credit Facilities

At December 31, 2004, the company had available credit facilities of $1,730 million, of which $1,510 million was undrawn, as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2006	200
Facility that is fully revolving for a period of three years and expires in 2007	1 500
Facilities that can be terminated at any time at the option of the lenders	30
Total available credit facilities	1 730
Credit facilities supporting outstanding commercial paper and standby letters of credit	220
Total undrawn credit facilities	1 510

At December 31, 2004, the company had issued $131 million in letters of credit to various third parties.

7. FINANCIAL INSTRUMENTS

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities, and interest rates. Suncor uses derivatives to reduce (hedge) its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures manage the exposure to losses that could result if commodity prices or foreign currency exchange rates change adversely.

An option is a contract where its holder, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges can protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limits the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate, or vice versa; a domestic currency debt may be converted to a foreign currency debt.

See below for more technical details and amounts.

(a) Balance Sheet Financial Instruments

The company's financial instruments recognized in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts not accounted for as hedges, substantially all current liabilities (except for the current portions of income taxes payable, future income taxes and retirement obligations), and long-term debt.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The following table summarizes estimated fair value information about the company's financial instruments recognized in the Consolidated Balance Sheets at December 31:

	2004		2003	
($ millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	**88**	**88**	388	388
Accounts receivable	**627**	**627**	505	505
Current liabilities	**1 252**	**1 252**	976	976
Long-term debt				
Fixed-term	**2 104**	**2 339**	2 317	2 502
Revolving-term	**89**	**89**	—	—
Other	**5**	**5**	4	4
Capital leases	**19**	**19**	127	127

The fair values of the company's fixed and revolving-term long-term debt, capital leases, and other long-term debt were determined through comparisons to similar debt instruments.

(b) Unrecognized Derivative Financial Instruments

The company is also a party to certain derivative financial instruments that are not recognized in the Consolidated Balance Sheets, as follows:

Revenue and Margin Hedges

Suncor operates in a global industry where the market price of its petroleum and natural gas products is determined based on floating benchmark indices denominated in U.S. dollars. The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude sales price variability by entering into U.S. dollar West Texas Intermediate (WTI) derivative transactions. As at December 31, 2004, the company had hedged a portion of its forecasted Canadian dollar denominated cash flows subject to U.S. dollar WTI commodity price risk until

December 31, 2005. The company had not hedged any portion of the foreign exchange component of these forecasted cash flows. As a result of the company's decision to suspend its strategic crude oil hedging program, no strategic crude oil hedges were entered into in 2004.

At December 31, 2004, the company had also hedged a portion of its forecasted cash flows related to natural gas production and refinery operations.

The financial instrument contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or payments by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

Contracts outstanding at December 31 were as follows:

Strategic Crude Oil Hedges ($ millions except for average price)	Quantity (bpd)	Average Price [a]	Revenue Hedged ($ millions)	Hedge Period
As at December 31, 2004				
Crude oil swaps	**36 000**	**23**	**364** [c]	**2005**
As at December 31, 2003				
Crude oil swaps	68 000	24	772 [c]	2004
Costless collars	11 000	21 – 24	109 – 125 [c]	2004
Crude oil swaps	36 000	23	390 [c]	2005
As at December 31, 2002				
Crude oil swaps	10 000	30	57 [c]	2003 [b]
Crude oil swaps	15 000	24	208 [c]	2003
Costless collars	60 000	21 – 26	726 – 899 [c]	2003
Crude oil swaps	25 000	23	332 [c]	2004
Costless collars	11 000	21 – 24	133 – 152 [c]	2004
Crude oil swaps	21 000	22	266 [c]	2005

Margin Hedges	Quantity (bpd)	Average Margin US$/bbl	Margin Hedged	Hedge Period
Refined product sale and crude purchase swaps				
As at December 31, 2004	**6 300**	**7**	**15** [c]	**2005** [d]
As at December 31, 2003	6 600	5	3 [c]	2004 [e]
As at December 31, 2002	20 700	5	9 [c]	2003 [f]

Natural Gas Hedges	Quantity (GJ/day)	Average Price Cdn$/GJ	Revenue Hedged	Hedge Period
Swaps and costless collars				
As at December 31, 2004				
Natural gas swaps	**4 000**	**7**	**10**	**2005**
Natural gas swaps	**4 000**	**7**	**10**	**2006**
Natural gas swaps	**4 000**	**6**	**9**	**2007**
Costless collars	**10 000**	**8 – 9**	**7 – 8**	**2005** [g]
As at December 31, 2003 [j]	30 000	6	16	2004 [h]
As at December 31, 2002 [k]	25 000	4 – 6	9 – 14	2003 [i]

(a) Average price for crude oil swaps is US$/barrel WTI at Cushing.
(b) For the period January to April 2003, inclusive. All other crude oil positions are for the full year.
(c) The revenue and margin hedged is translated to Cdn$ at the year-end exchange rate for convenience purposes.
(d) For the period January to September 2005.
(e) For the period January and February 2004.
(f) For the period January and February 2003.
(g) For the period January to March 2005.
(h) For the period January to March 2004.
(i) For the period January to March 2003.
(j) As of December 31, 2003, only swap hedges were outstanding.
(k) As of December 31, 2002, only costless collar hedges were outstanding.

Interest Rate Hedges

The company periodically enters into interest rate swap contracts as part of its risk management strategy to manage its exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

The notional amounts of interest rate swap contracts outstanding at December 31, 2004, are detailed in note 6, Long-term Debt.

Fair Value of Derivative Financial Instruments

The fair value of hedging derivative financial instruments is the estimated amount, based on broker quotes and/or internal valuation models, that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ millions)	**2004**	2003
Revenue hedge swaps and collars	**(305)**	(285)
Margin hedge swaps	**5**	2
Interest rate and cross-currency interest rate swaps	**36**	32
	(264)	(251)

(c) Energy Marketing and Trading Activities

In addition to those financial derivatives used for hedging activities, the company also uses energy derivatives, including physical and financial swaps, forwards, futures and options to gain market information and earn trading revenues. These energy trading activities are accounted for using the mark-to-market method and, as such, physical and financial energy contracts are recorded at fair value at each balance sheet date. During 2004 Suncor recorded a net pretax gain of $11 million (2003 – pretax loss of $3 million; 2002 – $nil) related to the settlement and revaluation of financial energy trading contracts. In 2004 the settlement of physical trading activities also resulted in a net pretax gain of $12 million (2003 – $2 million; 2002 – $6 million). These gains were included as energy trading and marketing activities in the Consolidated Statement of Earnings. The above amounts do not include the impact of related general and administrative costs.

The fair value of unsettled financial energy trading assets and liabilities at December 31 were as follows:

($ millions)	**2004**	2003
Energy trading assets	**26**	5
Energy trading liabilities	**9**	5

The source of the valuations of the above contracts was based on actively quoted prices and internal valuation models.

(d) Counterparty Credit Risk

The company may be exposed to certain losses in the event that counterparties to the derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. The company minimizes this risk by entering into agreements with counterparties, of which substantially all are investment grade. Risk is also minimized through regular management review of credit ratings and potential exposure to such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	**2004**	2003
Derivative contracts not accounted for as hedges	**7**	30
Unrecognized derivative contracts	**21**	27
	28	57

8. ACCRUED LIABILITIES AND OTHER

($ millions)	**2004**	2003
Asset retirement obligations [(a)]	**429**	363
Employee future benefits liability (see note 9)	**183**	181
Employee and director incentive plans	**50**	35
Deferred revenue	**64**	—
Environmental remediation costs [(b)]	**8**	34
Other	**15**	3
Total	**749**	616

(a) Asset Retirement Obligations

The asset retirement obligation also includes $47 million in current liabilities (2003 – $38 million). The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the long-term obligations associated with the retirement of property, plant and equipment.

($ millions)	2004	2003
Asset retirement obligations, beginning of year	**401**	400
Liabilities incurred	**82**	—
Liabilities settled	**(33)**	(24)
Accretion of asset retirement obligations	**26**	25
Asset retirement obligations, end of period	**476**	401

The total undiscounted amount of estimated cash flows required to settle the obligations at December 31, 2004, was approximately $1.1 billion (2003 – $1.0 billion), and has been discounted using a credit-adjusted risk-free rate of 6% (2003 – 6.5%). Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 35 years.

A significant portion of the company's assets have retirement obligations for which the fair value cannot be reasonably determined because the assets currently have an indeterminate life. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

(b) Environmental Remediation Costs

Total accrued environmental remediation costs also include $35 million in current liabilities (2003 – $20 million).

9. EMPLOYEE FUTURE BENEFITS LIABILITY

Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire. The related ***Benefit Obligation*** *or commitment that Suncor has to employees and retirees at December 31, 2004, was $752 million.*

As required by government regulations and plan performance, Suncor sets aside funds with an independent trustee to meet certain of these obligations. At the end of December 2004, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $399 million.*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $353 million represents the* ***Net Unfunded Obligation****.*

See below for more technical details and amounts.

Defined Benefit Pension Plans and Other Post-retirement Benefits

The company's defined benefit pension plans provide non-indexed pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unfunded, unregistered supplementary benefits that are paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the funded pension plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation for the Canadian and U.S. plans was performed in 2004.

The company's other post-retirement benefits programs, which are unfunded, include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian GAAP and actuarial principles. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement.

Obligations and Funded Status

The following table presents information about obligations recognized in the Consolidated Balance Sheets and the funded status of the plans at December 31:

($ millions)	Pension Benefits 2004	Pension Benefits 2003	Other Post-retirement Benefits 2004	Other Post-retirement Benefits 2003
Change in benefit obligation				
Benefit obligation at beginning of year	**568**	489	**117**	97
Service costs	**25**	18	**5**	3
Interest costs	**34**	32	**7**	6
Plan participants' contributions	**3**	3	**—**	—
Acquisition [a]	**—**	14	**—**	6
Foreign exchange	**(2)**	(1)	**(1)**	—
Actuarial loss	**21**	37	**4**	8
Benefits paid	**(25)**	(24)	**(4)**	(3)
Benefit obligation at end of year [b], [f]	**624**	568	**128**	117
Change in plan assets [c]				
Fair value of plan assets at beginning of year	**336**	273	**—**	—
Actual return on plan assets	**33**	45	**—**	—
Employer contributions	**49**	36	**—**	—
Plan participants' contributions	**3**	3	**—**	—
Benefits paid	**(22)**	(21)	**—**	—
Fair value of plan assets at end of year [f]	**399**	336	**—**	—
Net unfunded obligation	**(225)**	(232)	**(128)**	(117)
Items not yet recognized in earnings:				
Unamortized net actuarial loss [d]	**125**	133	**49**	50
Unamortized past service costs [e]	**—**	—	**(29)**	(31)
Accrued benefit liability	**(100)**	(99)	**(108)**	(98)
Current liability	**(40)**	(14)	**(3)**	(2)
Long-term liability	**(78)**	(85)	**(105)**	(96)
Long-term asset	**18**	—	**—**	—
Total accrued benefit liability	**(100)**	(99)	**(108)**	(98)

(a) In 2003, in connection with the acquisition of the Denver refinery and related assets from ConocoPhillips, the company assumed a pension benefit obligation of $14 million and other post-retirement benefit obligations of $6 million. No pension plan assets were acquired.

(b) Obligations are based on the following assumptions:

(per cent)	Pension Benefit Obligations 2004	Pension Benefit Obligations 2003	Other Post-retirement Benefits Obligation 2004	Other Post-retirement Benefits Obligation 2003
Discount rate	**5.75**	6.00	**5.75**	6.00
Rate of compensation increase	**4.50**	4.00	**4.25**	4.00

A one percent change in the assumptions at which pension benefits and other post-retirement benefits liabilities could be effectively settled is as follows:

($ millions)	Rate of Return on Plan Assets 1% increase	Rate of Return on Plan Assets 1% decrease	Discount Rate 1% increase	Discount Rate 1% decrease	Rate of Compensation Increase 1% increase	Rate of Compensation Increase 1% decrease
Increase (decrease) to net periodic benefit cost	(4)	4	(11)	12	6	(5)
Increase (decrease) to benefit obligation	—	—	(99)	115	30	(27)

In order to measure the expected cost of other post-retirement benefits, an 11.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004 (2003 – 12%; 2002 – 9%). It is assumed that this rate will decrease by 0.5% annually, to 5% for 2017, and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for other post-retirement benefit obligations. A one per cent change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(1)
Increase (decrease) to the health care component of the accumulated Post-retirement benefit obligation	13	(11)

(c) Pension plan assets are not the company's assets and therefore are not included in the Consolidated Balance Sheets.

(d) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 12 years for pension benefits (2003 – 12 years; 2002 – 13 years), and over the expected average future service life to full eligibility age of 12 years for other post-retirement benefits (2003 and 2002 – 12 years).

(e) Effective April 1, 2003, the company implemented amendments to its post-retirement benefits program to manage its exposures to future health care and life insurance costs. Certain of the company's employees will continue to receive post-retirement benefits under the old plan provisions. These plan amendments reduced the company's other post-retirement benefits obligation at December 31, 2002, by $34 million.

(f) The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation.

The above benefit obligation at year-end includes funded and unfunded plans, as follows:

	Pension Benefits		Other Post-retirement Benefits	
($ millions)	**2004**	2003	**2004**	2003
Funded plans	**537**	498	**—**	—
Unfunded plans	**87**	70	**128**	117
Benefit obligation at end of year	**624**	568	**128**	117

Components of Net Periodic Benefit Cost [(a)]

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	**2004**	2003	2002	**2004**	2003	2002
Current service costs	**25**	18	17	**5**	3	4
Interest costs	**34**	32	30	**7**	6	6
Expected return on plan assets [(b)]	**(25)**	(20)	(22)	**—**	—	—
Amortization of net actuarial loss	**19**	22	15	**1**	1	2
Net periodic benefit cost recognized [(c)]	**53**	52	40	**13**	10	12

Components of Net Incurred Benefit Cost [(a)]

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	**2004**	2003	2002	**2004**	2003	2002
Current service costs	**25**	18	17	**5**	3	4
Interest costs	**34**	32	30	**7**	6	6
Actual (return) loss on plan assets	**(33)**	(45)	24	**—**	—	—
Amendments	**—**	—	—	**—**	—	(34)
Actuarial (gain) loss	**21**	37	(1)	**4**	8	30
Net incurred benefit cost	**47**	42	70	**16**	17	6

(a) The net periodic benefit cost includes certain accounting adjustments made to allocate costs to the periods in which employee services are rendered, consistent with the long-term nature of the benefits. Costs actually incurred in the period (arising from actual returns on plan assets and actuarial gains and losses in the period) differ from allocated costs recognized.

(b) The expected return on plan assets is the expected long-term rate of return on plan assets for the year. It is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between it and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 12 years for pension benefits.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

(c) Pension expense is based on the following assumptions:

	Pension Benefit Expense			Other Post-retirement Benefits Expense		
(per cent)	**2004**	2003	2002	**2004**	2003	2002
Discount rate	**6.00**	6.50	6.50	**6.00**	6.50	6.50
Expected return on plan assets	**7.00**	7.25	7.25	**—**	—	—
Rate of compensation increase	**4.00**	4.00	4.25	**4.00**	4.00	4.25

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are managed by external managers, who report to a Pension Committee, and are restricted to those permitted by applicable legislation. Investments are made through pooled, mutual or segregated funds.

The company's pension plan asset allocation based on market values as at December 31, 2004 and 2003, and the target allocation for 2005 is as follows:

	Target Allocation %	Percentage of Plan Assets	
	2005	**2004**	2003
Asset Category			
Equities	60	**60**	61
Fixed income	40	**40**	39
Total	100	**100**	100

Equity securities do not include any direct investments in Suncor shares.

Cash Flows

The company expects that contributions to its pension plans in 2005 will be $65 million, including approximately $15 million for the company's senior executive and supplemental retirement plans. Expected benefit payments from the plans are as follows:

	Pension Benefits	Other Post-retirement Benefits
2005	27	4
2006	29	5
2007	31	5
2008	33	6
2009	34	7
2010 – 2014	211	49
Total	365	76

Defined Contribution Pension Plan

The company has a Canadian defined contribution plan and a U.S. 401(k) savings plan, under which both the company and employees make contributions. Company contributions and corresponding expense totalled $8 million in 2004 (2003 – $6 million; 2002 – $5 million).

10. INCOME TAXES

*The assets and liabilities shown on Suncor's balance sheets are calculated in accordance with Canadian GAAP. Suncor's income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes. These differences are known as **temporary differences**, because eventually these differences will reverse.*

*The amount shown on the balance sheets as **future income taxes** represent income taxes that will eventually be payable or recoverable in future years when these temporary differences reverse.*

See next page for more technical details and amounts.

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the two rates and the dollar effect is as follows:

($ millions)	2004 Amount	%	2003 Amount	%	2002 Amount	%
Federal tax rate	**589**	**36**	666	37	428	38
Provincial abatement	**(164)**	**(10)**	(180)	(10)	(113)	(10)
Federal surtax	**18**	**1**	20	1	13	1
Provincial tax rates	**192**	**12**	225	13	148	13
Statutory tax and rate	**635**	**39**	731	41	476	42
Adjustment of statutory rate for future rate reductions	**(86)**	**(5)**	(92)	(6)	—	—
	549	**34**	639	35	476	42
Add (deduct) the tax effect of:						
Crown royalties	**133**	**8**	50	3	39	3
Resource allowance	**(69)**	**(4)**	(31)	(2)	(34)	(3)
Temporary difference in resource allowance	**—**	**—**	—	—	(117)	(10)
Large corporations tax	**18**	**1**	19	1	17	1
Tax rate changes on opening future income taxes	**(53)**	**(3)**	89	5	(10)	(1)
Attributed Canadian royalty income	**(29)**	**(2)**	(8)	—	(2)	—
Stock-based compensation	**8**	**—**	3	—	—	—
Assessments and adjustments	**—**	**—**	—	—	10	1
Capital gains	**(18)**	**(1)**	(34)	(2)	—	—
Other	**(3)**	**—**	(1)	—	(1)	—
Income taxes and effective rate	**536**	**33**	726	40	378	33

In 2004 net income tax payments totalled $50 million (2003 – $45 million payment; 2002 – $8 million refund).

The resource allowance is a federal tax deduction allowed as a proxy for non-deductible provincial Crown royalties. As required by Canadian GAAP, resource allowance is accounted for by adjusting the statutory tax rate by the resource allowance rate.

Effective January 1, 2003, the Canadian government enacted changes to the federal taxation policies relating to the resource sector. The changes are to be fully phased in by 2007 and include a 7% reduction of the federal rate, deductibility of provincial Crown royalties and the elimination of the federal resource allowance deduction. In 2004 and 2003, the company's future income tax liabilities related to its resource operations were based on the future tax rates with the full 7% federal tax rate reduction.

Effective April 1, 2004, the Alberta provincial corporate tax rate decreased by 1% (2003 – decrease of 1%). In 2003 the Ontario government substantively enacted a general corporate tax rate and manufacturing and processing tax rate increase of 1.5% and 1% respectively, effective January 1, 2004.

Accordingly, in 2004, the company revalued its future income tax liabilities and recognized a decrease in future income tax expense of $53 million (2003 – increase of $89 million).

At December 31, future income taxes were comprised of the following:

($ millions)	2004 Current	2004 Non-current	2003 Current	2003 Non-current
Future income tax assets:				
Employee future benefits	**14**	**—**	4	—
Asset retirement obligations	**16**	**—**	9	—
Inventories	**27**	**—**	2	—
	57	**—**	15	—
Future income tax liabilities:				
Depreciation	**—**	**2 734**	—	2 095
Overburden removal costs	**—**	**20**	—	16
Deferred maintenance shutdown costs	**—**	**44**	—	41
Inventories	**—**	**—**	(12)	—
Employee future benefits	**—**	**(77)**	—	(70)
Asset retirement obligations	**—**	**(139)**	—	(7)
Attributed Canadian royalty income	**—**	**(69)**	—	(47)
Other	**—**	**19**	13	(6)
	—	**2 532**	1	2 022

11. COMMITMENTS, CONTINGENCIES, GUARANTEES AND SUBSEQUENT EVENT

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company periodically enters into transportation service agreements for pipeline capacity and energy services agreements as well as non-cancellable operating leases for service stations, office space and other property and equipment. Under contracts existing at December 31, 2004, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services (1)	Operating Leases
2005	178	44
2006	190	31
2007	190	27
2008	210	22
2009	211	15
Later years	3 626	54
	4 605	193

(1) Includes annual tolls payable under a transportation service agreement with a major pipeline company to use a portion of its pipeline capacity and tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreement commenced in 1999 and extends to 2028. As the initial shipper on the pipeline, Suncor's tolls payable under the agreement are subject to annual adjustments.

To meet the energy needs of its oil sands operation, Suncor has a commitment under long-term energy agreements to obtain a portion of the power and all of the steam generated by a cogeneration facility owned by a major third-party energy company. Since October 1999, this third-party has managed the operations of Suncor's existing energy services facility.

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the recognition of estimated asset retirement obligations. Effective January 1, 2004, the company adopted new Canadian accounting standards that required recognition of a liability for the future retirement obligations associated with the company's property, plant and equipment (see Summary of Significant Accounting Policies and Note 1). Estimates of retirement obligation costs can change significantly based on such factors as operating experience, changes in legislation and regulations and cost.

The company carries property loss and business interruption insurance policies with a combined coverage limit of up to US$1,150 million, net of deductible amounts. The primary property loss policy of US$250 million has a deductible of US$10 million per incident and the primary business interruption policy of US$200 million has a deductible per incident of the greater of US$50 million gross earnings lost (as defined in the insurance policy) or 30 days from the incident. In addition to these primary coverage insurance policies, Suncor has excess coverage of US$700 million that can be used for either property loss or business interruption coverage. For business interruption purposes this excess coverage begins the later of full utilization of the primary business interruption coverage or 90 days from the date of the incident.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash provided from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Variable Interest Entities and Guarantees

At December 31, 2004, the company had off-balance sheet arrangements with Variable Interest Entities, and indemnification agreements with other third parties, as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less, to a third-party. The third-party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2004, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses for certain counterparties, which did not exceed $50 million in 2004. A liability has not been recorded for this

indemnification as the company believes it has no significant exposure to credit losses. There were no new securitization proceeds in 2004. Proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2004 were approximately $2,073 million. The company recorded an after-tax loss of approximately $2 million on the securitization program in 2004 (2003 and 2002 – $3 million).

In 1999, the company entered into an equipment sale and leaseback arrangement with a third-party for proceeds of $30 million. The third-party's sole asset is the equipment sold to it and leased back by the company. The initial lease term covers a period of seven years and as at December 31, 2004, was accounted for as an operating lease. The company has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. An early termination purchase option allows for the repurchase of the equipment at a specified date in 2005. Had the company elected to terminate the lease at December 31, 2004, the total cost would have been $25 million. Annualized equipment lease payments in 2004 were $6 million (2003 – $4 million; 2002 – $2 million).

The company has agreed to indemnify holders of the 7.15% notes, the 5.95% notes and the company's credit facility lenders (see note 6) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, and certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

(d) Subsequent Event
On January 4, 2005, a fire occurred at the company's Oil Sands operations. The fire was confined to one of the upgraders, primarily affecting a coker fractionator. Daily production capacity at the Oil Sands facility has been reduced during the investigation and repair of fire-related damage.

12. PREFERRED SECURITIES

On March 15, 2004, the company redeemed all of its then outstanding 9.05% and 9.125% preferred securities for total cash consideration of $493 million. In 2004, dividends of $9 million were paid on the preferred securities (2003 – $45 million; 2002 – $48 million).

13. SHARE CAPITAL

(a) Authorized:

Common Shares
The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares
The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

(b) Issued:

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2002	448 972	578
Issued for cash under stock option plans	1 977	20
Issued under dividend reinvestment plan	235	6
Balance as at December 31, 2003	451 184	604
Issued for cash under stock option plans	**2 880**	**41**
Issued under dividend reinvestment plan	**177**	**6**
Balance as at December 31, 2004	**454 241**	**651**

Common Share Options

A common share option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees and directors that hold options must earn the right to exercise them. This is done by the employee or director fulfilling a time requirement for service to the company, and with respect to certain options, subject to accelerated vesting should the company meet predetermined performance criteria. Once this right has been earned, these options are considered vested.

The predetermined price at which an option can be exercised is equal to or greater than the market price of the common shares on the date the options are granted.

See below for more technical details and amounts on the company's stock option plans:

(i) EXECUTIVE STOCK PLAN Under this plan, the company granted 1,346,000 common share options in 2004 (2003 – 1,902,000; 2002 – 1,803,000) to non-employee directors and certain executives and other senior employees of the company. The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted have a 10-year life and vest annually over a three-year period.

(ii) SUNSHARE PERFORMANCE STOCK OPTION PLAN During 2004, the company granted 1,742,000 options (2003 – 1,305,000; 2002 – 8,938,000) to eligible permanent full-time and part-time employees, both executive and non-executive, under its employee stock option incentive plan ("SunShare"). Under SunShare, meeting specified performance targets accelerates the vesting of some or all options.

In October 2004, the company met the predetermined performance criteria for the accelerated vesting of 2,097,000 common share options granted to executive and non-executive employees. The vested options represented approximately 20% of the then outstanding common share options granted under the SunShare plan. An additional 2,062,000 options, representing approximately 25% of outstanding SunShare options at December 31, 2004, will vest on January 31, 2005 in connection with the achievement of the second predetermined performance criterion. The remaining 60% of outstanding SunShare options may vest on April 30, 2008. All unvested options, which have not previously expired or been cancelled, will automatically vest on January 1, 2012.

In 2004, the Board of Directors approved an additional 3,000,000 options available for grant under the SunShare plan.

(iii) KEY CONTRIBUTOR STOCK OPTION PLAN In 2004, the Board of Directors approved the establishment of the new Key Contributor stock option plan, under which 5,200,000 options were made available for grant to senior managers and key employees.

(iv) DEFERRED SHARE UNITS (DSUs) The company had 1,228,000 DSUs outstanding at December 31, 2004. DSUs were granted to certain executives under the company's former employee long-term incentive program. Certain members of the Board of Directors have also elected to receive DSUs in lieu of cash compensation. DSUs are only redeemable at the time a unitholder ceases employment or Board membership, as applicable.

In 2004, there were no redemptions of DSUs for cash (2003 – 185,000 redeemed for cash consideration of $5 million; 2002 – 220,000 redeemed for cash consideration of $6 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. Final DSU redemption amounts are subject to change depending on the company's share price at the time of exercise. Accordingly, the company revalues the DSUs on each reporting date, with any changes in value recorded as an adjustment to compensation expense in the period. As at December 31, 2004, the total liability related to the DSUs was $52 million, of which $2 million was classified as current (see note 8).

During 2004, total pretax compensation expense related to deferred share units was $12 million (2003 – $8 million; 2002 – income of $2 million).

(v) PERFORMANCE SHARE UNITS (PSUs) During 2004, the company issued 354,000 PSUs (2003 and 2002 – nil) under its new employee incentive compensation plan. PSUs granted replace the remuneration value of reduced grants under the company's stock option plans. PSUs vest and are settled in cash approximately three years after the grant date to varying degrees (0%, 50%, 100% and 150%) contingent upon Suncor's performance. Performance is measured by reference to the company's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. Expense related to the PSUs is accrued based on the price of common shares at the end of the period and the probability of vesting. This expense is recognized on a straight-line basis over the term of the grant. Pretax expense recognized for PSUs during 2004 was $5 million (2003 and 2002 – $nil).

The following tables cover all common share options granted by the company for the years indicated:

	Number (thousands)	Range of Exercise Prices ($)	Weighted-average Exercise Price Per Share ($)
Outstanding, December 31, 2001	11 768	2.38 – 21.35	12.12
Granted	10 741	23.93 – 28.14	27.08
Exercised	(1 777)	2.38 – 17.45	10.42
Cancelled	(406)	13.04 – 27.65	26.48
Outstanding, December 31, 2002	20 326	3.80 – 28.14	19.89
Granted	3 207	23.65 – 29.85	26.70
Exercised	(1 977)	3.80 – 23.93	10.35
Cancelled	(540)	10.13 – 27.93	20.94
Outstanding, December 31, 2003	21 016	4.11 – 29.85	21.69
Granted	3 088	30.63 – 42.02	34.52
Exercised	(2 880)	4.11 – 40.67	13.94
Cancelled	(537)	23.93 – 41.38	28.71
Outstanding, December 31, 2004	**20 687**	**5.22 – 42.02**	**24.49**
Exercisable, December 31, 2004	**9 067**	**5.22 – 40.67**	**18.78**

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:

(thousands of common shares)	**2004**	2003	2002
	4 342	6 893	11 175

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2004:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-average Remaining Contractual Life	Weighted-average Exercise Price Per Share ($)	Number (thousands)	Weighted-average Exercise Price Per Share ($)
5.22 – 10.13	1 459	3	8.82	1 459	8.82
12.28 – 21.35	4 040	4	15.22	4 040	15.22
23.65 – 28.93	12 265	7	27.01	3 282	26.27
30.63 – 42.02	2 923	8	34.58	286	33.82
Total	20 687	6	24.49	9 067	18.78

(vi) FAIR VALUE OF OPTIONS GRANTED The fair values of all common share options granted are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the year and the weighted-average assumptions used in their determination are as noted below:

	2004	2003	2002
Annual dividend per share	**$0.23**	$0.1925	$0.17
Risk-free interest rate	**3.79%**	4.39%	5.39%
Expected life	**6 years**	7 years	8 years
Expected volatility	**29%**	32%	31%
Weighted-average fair value per option	**$12.02**	$9.94	$12.08

The company's reported net earnings attributable to common shareholders and earnings per share prepared in accordance with the fair value method of accounting for stock-based compensation would have been reduced for all common share options granted prior to 2003 to the pro forma amounts stated below:

($ millions, except per share amounts)	**2004**	2003	2002
Net earnings attributable to common shareholders – as reported	**1 088**	1 085	722
Less: compensation cost under the fair value method for pre-2003 options	**47**	30	32
Pro forma net earnings attributable to common shareholders for pre-2003 options	**1 041**	1 055	690
Basic earnings per share			
As reported	**2.40**	2.41	1.61
Pro forma	**2.30**	2.35	1.54
Diluted earnings per share			
As reported	**2.36**	2.24	1.58
Pro forma	**2.26**	2.18	1.51

14. EARNINGS PER COMMON SHARE

The following is a reconciliation of basic and diluted earnings per common share:

($ millions)	**2004**	2003	2002
Net earnings attributable to common shareholders	**1 088**	1 085	722
Dividends on preferred securities, net of tax	— [a]	27	28
Revaluation of US$ preferred securities, net of tax	— [a]	(37)	(1)
Adjusted net earnings attributable to common shareholders	**1 088**	1 075	749
(millions of common shares)			
Weighted-average number of common shares	**453**	450	448
Dilutive securities:			
Options issued under stock-based compensation plans	**9**	8	5
Redemption of preferred securities by the issuance of common shares	— [a]	22	20
Weighted-average number of diluted common shares	**462**	480	473
(dollars per common share)			
Basic earnings per share [b]	**2.40**	2.41	1.61
Diluted earnings per share	**2.36**	2.24 [c]	1.58 [c]

Common share and earnings per common share amounts in the above table reflect a two-for-one share split effective May 15, 2002.

Note: An option will have a dilutive effect under the treasury stock method only when the average market price of the common stock during the period exceeds the exercise price of the option.

(a) For the year ended December 31, 2004, diluted earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of diluted common shares. Dividends on preferred securities, the revaluation of US$ preferred securities and the redemption of preferred securities by the issuance of common shares have an anti-dilutive impact, therefore they are not included in the calculation of diluted earnings per share. The company redeemed its preferred securities in the first quarter of 2004.

(b) Basic earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

(c) Diluted earnings per share is the adjusted net earnings attributable to common shareholders, divided by the weighted-average number of diluted common shares.

15. FINANCING EXPENSES (INCOME)

($ millions)	**2004**	2003	2002
Interest on debt	**148**	140	155
Capitalized interest	**(61)**	(57)	(22)
Net interest expense	**87**	83	133
Foreign exchange (gain) on long-term debt	**(89)**	(166)	(9)
Other foreign exchange loss	**11**	17	—
Total financing expenses (income)	**9**	(66)	124

Cash interest payments in 2004 totalled $143 million (2003 – $139 million; 2002 – $134 million).

16. INVENTORIES

($ millions)	**2004**	2003
Crude oil	**109**	135
Refined products	**120**	134
Materials, supplies and merchandise	**194**	102
Total	**423**	371

As at December 31, 2004, the replacement cost of crude oil and refined product inventories, valued using the LIFO cost method, exceeded their carrying value by $65 million (2003 – $48 million).

During 2004, the company recorded a pretax gain of $8 million related to a permanent reduction in LIFO inventory layers.

17. RELATED PARTY TRANSACTIONS

The following table summarizes the company's related party transactions after eliminations for the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

($ millions)	**2004**	2003	2002
Operating revenues			
Sales to Energy Marketing and Refining – Canada segment joint-ventures:			
Refined products	**320**	301	321
Petrochemicals	**272**	187	142

The company has supply agreements with two Energy Marketing and Refining – Canada segment joint-ventures for the sale of refined products. The company also has a supply agreement with an Energy Marketing and Refining – Canada segment joint-venture for the sale of petrochemicals.

At December 31, 2004, amounts due from Energy Marketing and Refining – Canada segment joint-ventures were $17 million (2003 – $36 million).

Sales to and balances with Energy Marketing and Refining – Canada segment joint-ventures are established and agreed to by the various parties and approximate fair value.

18. SUPPLEMENTAL INFORMATION

($ millions)	2004	2003	2002
Export sales [a]	**693**	549	501
Exploration expenses			
Geological and geophysical	**33**	18	13
Other	**1**	1	2
Cash costs	**34**	19	15
Dry hole costs	**21**	32	11
Cash and dry hole costs [b]	**55**	51	26
Leasehold impairment [c]	**8**	16	10
	63	67	36
Taxes other than income taxes			
Excise taxes [d]	**452**	388	340
Production, property and other taxes	**44**	38	34
	496	426	374
Allowance for doubtful accounts	**3**	4	

(a) Sales of crude oil, natural gas and refined products to customers in the United States and sales of petrochemicals to customers in the United States and Europe.

(b) Included in exploration expenses in the Consolidated Statements of Earnings.

(c) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings.

(d) Included in operating revenues in the Consolidated Statements of Earnings.

In 2002, the company sold its retail natural gas marketing business in the Energy Marketing and Refining – Canada segment for cash consideration of $62 million, net of related closing costs and adjustments of $4 million, resulting in an after-tax gain of $35 million.

19. DIFFERENCES BETWEEN CANADIAN AND U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on earnings and comprehensive income as reported:

($ millions)	Notes	2004	2003	2002
Net earnings as reported, Canadian GAAP		**1 100**	1 075	749
Adjustments net of applicable income taxes				
Derivatives and hedging activities	(a)	**65**	(120)	6
Stock-based compensation	(b)	**(10)**	(2)	(12)
Preferred securities	(c)	**(12)**	12	(29)
Asset retirement obligations	(d)	**—**	5	12
Cumulative effect of change in accounting principles	(d)	**—**	(66)	—
Net earnings attributable to discontinued operations	(f)	**—**	—	(56)
Net earnings from continuing operations, U.S. GAAP		**1 143**	904	670
Net earnings from discontinued operations, U.S. GAAP	(f)	**—**	—	56
Derivatives and hedging activities, net of income taxes of $35 (2003 – $7; 2002 – $54)	(a)	**(67)**	18	(118)
Minimum pension liability, net of income taxes of $3 (2003 – $nil; 2002 – $10)	(e)	**5**	7	(20)
Foreign currency translation adjustment	(g)	**(29)**	(26)	—
Comprehensive income, U.S. GAAP		**1 052**	903	588

per common share (dollars)	2004	2003	2002
Net earnings per share from continuing operations			
Basic	**2.52**	2.01	1.50
Diluted	**2.47**	1.86	1.47
Net earnings per share from discontinued operations			
Basic	**—**	—	0.12
Diluted	**—**	—	0.12

The application of U.S. GAAP would have the following effects on the Consolidated Balance Sheets as reported:

		December 31, 2004		December 31, 2003	
	Notes	As Reported	U.S. GAAP	As Reported	U.S. GAAP
Current assets	(a,h)	**1 195**	**1 300**	1 279	1 375
Property, plant and equipment, net	(c,h)	**10 289**	**10 340**	8 936	8 974
Deferred charges and other	(a,e)	**320**	**367**	286	333
Total assets		**11 804**	**12 007**	10 501	10 682
Current liabilities	(a)	**1 409**	**1 701**	1 060	1 349
Long-term borrowings	(a,h)	**2 217**	**2 275**	2 448	2 967
Accrued liabilities and other	(e)	**749**	**815**	616	692
Future income taxes	(a,c,e)	**2 532**	**2 526**	2 022	2 015
Preferred securities	(c)	**—**	**—**	476	—
Share capital	(b)	**651**	**699**	604	652
Contributed surplus	(b)	**32**	**44**	7	9
Cumulative foreign currency translation	(g)	**(55)**	**—**	(26)	—
Retained earnings		**4 269**	**4 176**	3 294	3 136
Accumulated other comprehensive income	(a,e,g)	**—**	**(229)**	—	(138)
Total liabilities and shareholders' equity		**11 804**	**12 007**	10 501	10 682

(a) Derivative Financial Instruments

The company accounts for its derivative financial instruments under Canadian GAAP as described in note 7. Financial Accounting Standards Board Statement (Statement) 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by Statements 138 and 149 (the Standards), establishes U.S. GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk each period are recognized in the Consolidated Statements of Earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") each period and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Accordingly, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges. Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same earnings statement caption as the hedged item.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges is based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

Commodity Price Risk

As described in note 7, Suncor manages crude price variability by entering into U.S. dollar WTI derivative transactions and has historically, in certain instances, combined U.S. dollar WTI derivative transactions and Canadian/U.S. foreign exchange derivative contracts. As at December 31, 2004 the company had hedged a portion of its forecasted Canadian dollar denominated cash flows subject to U.S. dollar WTI commodity price risk for 2005. The company had not hedged any portion of the foreign exchange component of these forecasted cash flows.

While the company's current strategic intent is to only manage the exposure relating to changes in the U.S. dollar WTI component of its crude oil sales, U.S. GAAP requires the company to consider all cash flows arising from forecasted Canadian dollar denominated crude oil sales when measuring the ineffectiveness of its cash flow hedges. In periods of significant Canadian/U.S. dollar foreign exchange fluctuations, material hedge ineffectiveness can result from unhedged foreign exchange exposures. This ineffectiveness arises despite the company's assessment that its U.S. dollar WTI hedging instruments are highly effective in achieving offsetting changes in cash flows attributable to its forecasted Canadian dollar denominated crude oil sales.

Under U.S. GAAP, for the year ended December 31, 2004, the company would have recognized $57 million of hedge ineffectiveness relating to forecasted cash flows in 2005 primarily due to foreign exchange fluctuations during the period. The net earnings impact of this ineffectiveness will not be recognized for Canadian GAAP purposes until the related forecasted crude oil sales occur in 2005.

Interest Rate Risk

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to minimize exposure to changes in cash flows of interest-bearing debt. At December 31, 2004, the company had interest rate derivatives classified as fair value hedges outstanding for up to seven years relating to fixed rate debt.

De-designated Hedging Instruments

During 2003, the company de-designated and monetized purchased crude oil call option hedging instruments for net proceeds of $28 million. For Canadian GAAP purposes, as it was probable that the underlying forecasted crude oil sales would occur, the related $28 million pretax gain on monetization of the call options was deferred and will be recognized as additional crude oil revenues during 2004. For US GAAP purposes, the company would have recognized the $28 million pre tax gain as hedge ineffectiveness income during 2003.

Non-designated Hedging Instruments

In 1999, the company sold inventory and subsequently entered into a derivative contract with an option to repurchase the inventory at the end of five years. The company realized an economic benefit as a result of liquidating a portion of its inventory. The derivative did not qualify for hedge accounting as the company did not have purchase price risk associated with the repurchase of the inventory. This derivative did not represent a U.S. GAAP difference as the company recorded this derivative at fair value for Canadian purposes.

During the fourth quarter of 2001, the company made a payment of $29 million to terminate a long-term natural gas contract. The contract had been designated as a hedge under Canadian GAAP, and the resulting settlement loss of $18 million, net of income taxes of $11 million, was to be deferred and recognized as the hedged item was settled. During 2002, in connection with the sale of the company's retail natural gas marketing business (see note 18), the company disposed of the related hedged item. Accordingly, for Canadian GAAP purposes, the company recognized the entire settlement loss of $18 million during 2002. For U.S. GAAP purposes, the long-term contract would have been designated as a normal purchase and sale transaction, and the after-tax loss of $18 million would have been recognized in 2001 on the initial settlement of the contract.

Accumulated OCI and U.S. GAAP Net Earnings Impacts

A reconciliation of changes in accumulated OCI attributable to derivative hedging activities for the years ended December 31 is as follows:

($ millions)	**2004**	2003
OCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $34 (2003 – $41)	**(71)**	(89)
Current period net changes arising from cash flow hedges, net of income taxes of $61 (2003 – $26)	**(122)**	(54)
Net hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $26 (2003 – $33)	**55**	72
OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $69 (2003 – $34)	**(138)**	(71)

For the year ended December 31, 2004, assets increased by $133 million and liabilities increased by $328 million as a result of recording all derivative instruments at fair value.

The loss associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $130 million, net of income taxes of $66 million (2003 – loss of $199 million, net of income taxes of $93 million; 2002 – loss of $19 million, net of income taxes of $9 million). The company estimates that $139 million of after-tax hedging losses will be reclassified from OCI to current period earnings within the next 12 months as a result of forecasted sales occurring.

For the year ended December 31, 2004, U.S. GAAP net earnings would have increased by $65 million, net of income taxes of $27 million (2003 – decreased net earnings of $120 million, net of income taxes of $56 million; 2002 – increased net earnings of $6 million, net of income taxes of $4 million) to reflect the impact of the above items.

(b) Stock-based Compensation
Under Canadian GAAP, compensation expense has not been recognized for common share options granted prior to January 1, 2003, including options issued in connection with both the company's SunShare long-term incentive plan, as well as those common shares and common share options awarded to employees under the company's previous long-term incentive program that matured April 1, 2002. Under U.S. GAAP, certain of the SunShare options would have been accounted for using the variable method of accounting for employee stock compensation. Further, for U.S. GAAP purposes, compensation expense would have been recognized ratably over the life of the previous long-term incentive program for those options and common shares awarded under that plan. For the year ended December 31, 2004, U.S. GAAP net earnings would have been reduced by $10 million (2003 – $2 million; 2002 – $12 million) to reflect additional stock-based compensation expense.

The company now expenses the compensation cost of all common share options issued after January 1, 2003, ratably over the estimated vesting period of the respective options. For U.S. GAAP purposes, the company would have adopted Statement 148 in 2003, permitting the company to expense common share options issued after January 1, 2003, in a manner consistent with Canadian GAAP.

Consistent with Canadian GAAP, for U.S. GAAP purposes the company would have continued to disclose pro forma stock-based compensation cost for common stock options awarded prior to January 1, 2003 ("pre-2003 options") as if the fair value method had been adopted. Under U.S. GAAP, had the company accounted for its pre-2003 options using the fair value method (excluding the earnings effect of the SunShare and long-term employee incentive options described above), pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2004, would have been reduced by $37 million (2003 – $27 million; 2002 – $24 million) and $0.08 per share (2003 – $0.06; 2002 – $0.05), respectively.

(c) Preferred Securities
Under Canadian GAAP, preferred securities were classified as shareholders' equity and the interest distributions thereon, net of income taxes, were accounted for as dividends. Under U.S. GAAP, the preferred securities would have been classified as long-term debt and the interest distributions thereon would have been accounted for as financing expenses. Preferred securities denominated in U.S. dollars of US$163 million would have been revalued at the rate in effect at the related balance sheet date, with any foreign exchange gains (losses) recognized in the Consolidated Statements of Earnings. Further, under U.S. GAAP the interest distributions would have been eligible for interest capitalization.

Under Canadian GAAP, issue costs of the preferred securities, net of the related income tax credits, were charged against shareholders' equity. Under U.S. GAAP, these issue costs would have been deferred and amortized to earnings over the term of the related long-term debt.

For U.S. GAAP purposes, these differences would have reduced net earnings for the year ended December 31, 2004 by $12 million, net of income taxes of $6 million (2003 – an increase to net earnings of $12 million, net of an income tax recovery of $8 million; 2002 – a reduction to net earnings of $29 million, net of income taxes of $20 million).

Under Canadian GAAP, the interest distributions on the preferred securities for the year ended December 31, 2004 of $9 million (2003 – $45 million; 2002 – $48 million) were classified as financing activities in the Consolidated Statements of Cash Flows. Under U.S. GAAP, the interest distributions of $9 million (2003 – $45 million; 2002 – $48 million) and the amortization of issue costs for the year ended December 31, 2004, of $1 million (2003 – $3 million; 2002 – $3 million) would have been classified as operating activities.

The preferred securities were redeemed on March 15, 2004.

(d) Asset Retirement Obligations
Under Canadian GAAP, the company retroactively adopted Canadian accounting standards related to asset retirement obligations (AROs) on January 1, 2004, with restatements of all prior period comparative amounts. Under U.S. GAAP the company would have adopted AROs on January 1, 2003, and would have been required to record the cumulative effect of the change in accounting policy in 2003 earnings. This GAAP difference would have decreased U.S. GAAP net earnings by $61 million in 2003 and increased net earnings by $12 million in 2002.

(e) Minimum Pension Liability
Under U.S. GAAP, recognition of an additional minimum pension liability is required when the accumulated benefit obligation exceeds the fair value of plan assets to the extent that such excess is greater than accrued pension costs otherwise recorded. For the purposes of determining the additional minimum pension liability, the accumulated benefit obligation does not incorporate projections of future compensation increases in the determination of the obligation. No such adjustment is required under Canadian GAAP.

Under U.S. GAAP, at December 31, 2004, the company would have recognized a minimum pension liability of $66 million (2003 – $76 million), an intangible asset of $11 million (2003 – $13 million) and other comprehensive loss of $36 million, net of income taxes of $19 million (2003 – $41 million, net of income taxes of $22 million). Other comprehensive income for the year ended December 31, 2004 would have increased by $5 million, net of income taxes of $3 million (2003 – an increase in other comprehensive income of $7 million, net of income taxes of $nil; 2002 – a decrease in other comprehensive income of $20 million, net of income taxes of $10 million).

(f) Discontinued Operations

During 2002, the company disposed of its retail natural gas business for net proceeds of $62 million, and recognized an after-tax gain on sale of $35 million for Canadian GAAP purposes. The retail natural gas marketing business was not considered significant to the company's overall business operations, and was not classified as a business segment for the purposes of discontinued operations reporting. Accordingly, financial results of the retail natural gas marketing business were not segregated from the financial results of the company's other operations prior to the date of disposal of the business.

For U.S. GAAP purposes, the company would have adopted Statement 144, "Accounting for the Impairment and Disposal of Long-Lived Assets," effective January 1, 2002. For the purposes of Statement 144, the retail natural gas business would have been considered a distinguishable component of the company, and reflected as a discontinued operation for the year ended December 31, 2002. For segmented reporting purposes, the retail natural gas marketing business was included in the Energy Marketing and Refining – Canada operating segment in 2002.

Selected financial information regarding the discontinued retail natural gas business is as follows for the year ended December 31:

($ millions)	**2004**	2003	2002
Revenues included in discontinued operations	—	—	81
Income from retail natural gas business operations, net of income taxes of $nil (2003 – $nil; 2002 – $4)	—	—	8
Gain on disposal of retail natural gas business, net of income taxes of $nil (2003 – $nil; 2002 – $10)	—	—	48

There were no remaining assets or liabilities related to the discontinued operations at December 31, 2004 or at December 31, 2003.

(g) Cumulative Foreign Currency Translation

Under Canadian GAAP, foreign currency losses of $29 million (2003 – $26 million) arising on translation of the company's Denver-based foreign operations have been recorded directly to shareholders' equity. Under U.S. GAAP, these foreign currency translation losses would be included as a component of comprehensive income.

(h) Variable Interest Entities

For U.S. GAAP purposes, the company would be required to consolidate the VIE related to the sale of equipment as described in note 11(c) as of January 1, 2004. The impact on the December 31, 2004, balance sheet would be an increase to property, plant and equipment of $14 million, an increase to inventory of $8 million and an increase to long-term debt of $22 million.

The accounts receivable securitization program, as currently structured, does not meet the FIN 46(R) criteria for consolidation by Suncor.

Recently Issued Accounting Standards

In December 2004, the U.S. Financial Accounting Standards Board issued SFAS 123(R), "Share-Based Payment". The standard, effective July 1, 2005, requires the recognition of an expense for employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The cost is to be recognized over the period for which an employee is required to provide the service in exchange for the award. In addition, SFAS 123(R) requires recognition of compensation expense for the portion of outstanding unvested awards granted prior to the effective date. The company currently records an expense under Canadian GAAP for all common share options issued on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. The company expects that adoption of SFAS 123(R) on July 1, 2005, for U.S. GAAP reporting will not have a significant impact on net earnings.

quarterly summary (unaudited)

FINANCIAL DATA

($ millions except per share amounts)	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Total Year 2004	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Total Year 2003
	For the Quarter Ended					For the Quarter Ended				
Revenues	**1 795**	**2 201**	**2 315**	**2 310**	**8 621**	1 700	1 385	1 788	1 698	6 571
Net earnings (loss)										
Oil Sands	**238**	**232**	**263**	**262**	**995**	305	70	259	254	888
Natural Gas	**22**	**35**	**23**	**35**	**115**	27	28	26	39	120
Energy Marketing and Refining – Canada	**30**	**(3)**	**29**	**24**	**80**	21	17	9	6	53
Refining and Marketing – U.S.A [(c)]	**(3)**	**12**	**15**	**10**	**34**	—	—	14	4	18
Corporate and eliminations	**(60)**	**(73)**	**7**	**2**	**(124)**	13	1	(17)	(1)	(4)
	227	**203**	**337**	**333**	**1 100**	366	116	291	302	1 075
Per common share										
Net earnings attributable to common shareholders										
Basic	**0.48**	**0.44**	**0.74**	**0.73**	**2.40**	0.84	0.27	0.63	0.67	2.41
Diluted	**0.46**	**0.43**	**0.73**	**0.72**	**2.36**	0.77	0.24	0.62	0.61	2.24
Cash dividends	**0.05**	**0.06**	**0.06**	**0.06**	**0.23**	0.0425	0.05	0.05	0.05	0.1925
Cash flow from (used in) operations										
Oil Sands	**365**	**421**	**509**	**457**	**1 752**	541	321	488	453	1 803
Natural Gas	**83**	**90**	**80**	**66**	**319**	88	66	80	64	298
Energy Marketing and Refining – Canada	**56**	**23**	**52**	**57**	**188**	49	41	27	47	164
Refining and Marketing – U.S.A [(c)]	**(6)**	**21**	**21**	**23**	**59**	—	—	25	9	34
Corporate and eliminations	**(76)**	**(65)**	**(77)**	**(79)**	**(297)**	(65)	(70)	(36)	(49)	(220)
	422	**490**	**585**	**524**	**2 021**	613	358	584	524	2 079

OPERATING DATA

OIL SANDS

(thousands of barrels per day)

	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Total Year 2004	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Total Year 2003
Production										
Base operations	**213.9**	**210.8**	**230.2**	**206.9**	**215.6**	211.1	188.2	231.5	235.2	216.6
Firebag	**5.9**	**15.1**	**7.3**	**15.6**	**10.9**	—	—	—	—	—
	219.8	**225.9**	**237.5**	**222.5**	**226.5**	211.1	188.2	231.5	235.2	216.6
Sales										
Light sweet crude oil	**112.2**	**118.7**	**113.5**	**115.3**	**114.9**	120.7	86.4	109.0	132.7	112.3
Diesel	**27.5**	**29.7**	**28.7**	**25.5**	**27.9**	30.1	22.9	24.8	27.2	26.3
Light sour crude oil	**74.3**	**68.9**	**76.3**	**80.9**	**75.1**	60.4	73.9	77.5	81.3	73.3
Bitumen	**—**	**14.5**	**7.9**	**11.0**	**8.4**	—	1.2	16.1	8.3	6.4
	214.0	**231.8**	**226.4**	**232.7**	**226.3**	211.2	184.4	227.4	249.5	218.3

OPERATING DATA (continued)

	For the Quarter Ended Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Total Year 2004	For the Quarter Ended Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Total Year 2003
OIL SANDS (continued)										
Average sales price [1]										
(dollars per barrel)										
Light sweet crude oil	**40.26**	**45.70**	**46.03**	**50.55**	**45.60**	46.69	39.87	37.96	36.67	40.26
Other (diesel, light sour crude oil and bitumen)	**35.85**	**38.28**	**42.29**	**39.62**	**39.13**	40.62	32.94	32.92	30.72	33.93
Total	**38.16**	**41.88**	**44.08**	**44.68**	**42.28**	44.09	36.19	35.34	33.89	37.19
Total [a]	**43.28**	**48.18**	**52.72**	**54.40**	**49.78**	48.77	38.14	38.05	36.63	40.22
(dollars per barrel sold rounded to the nearest $0.05)										
Cash operating costs and total operating costs – Base Operations										
Cash costs	**9.65**	**9.75**	**9.00**	**10.90**	**9.80**	9.20	10.70	8.20	9.25	9.25
Natural gas	**2.10**	**2.30**	**1.40**	**2.20**	**2.00**	3.10	2.45	1.65	1.60	2.15
Imported bitumen	**0.40**	**0.05**	**0.10**	**0.10**	**0.15**	0.10	0.10	—	—	0.05
Cash operating costs [2]	**12.15**	**12.10**	**10.50**	**13.20**	**11.95**	12.40	13.25	9.85	10.85	11.45
Firebag start-up costs	**1.20**	**—**	**—**	**—**	**0.30**	—	—	—	—	—
Total cash operating costs [3]	**13.35**	**12.10**	**10.50**	**13.20**	**12.25**	12.40	13.25	9.85	10.85	11.45
Depreciation, depletion and amortization	**6.20**	**6.15**	**5.70**	**6.25**	**6.10**	6.30	6.30	5.30	5.40	5.80
Total operating costs [4]	**19.55**	**18.25**	**16.20**	**19.45**	**18.35**	18.70	19.55	15.15	16.25	17.25
Cash operating costs and total operating costs – Firebag										
Cash costs	**—**	**6.55**	**14.90**	**7.00**	**8.30**	—	—	—	—	—
Natural gas	**—**	**11.65**	**11.90**	**10.45**	**11.20**	—	—	—	—	—
Cash operating costs [5]	**—**	**18.20**	**26.80**	**17.45**	**19.50**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**5.80**	**7.45**	**5.55**	**6.00**	—	—	—	—	—
Total operating costs [6]	**—**	**24.00**	**34.25**	**23.00**	**25.50**	—	—	—	—	—
NATURAL GAS										
Gross production [b]										
Natural gas (millions of cubic feet per day)	**197**	**209**	**201**	**193**	**200**	184	175	194	194	187
Natural gas liquids (thousands of barrels per day)	**2.2**	**2.2**	**2.6**	**2.9**	**2.5**	2.4	2.1	2.5	2.4	2.3
Crude oil (thousands of barrels per day)	**0.9**	**1.1**	**1.0**	**1.0**	**1.0**	1.4	1.6	1.6	1.0	1.4
Total (barrel of oil equivalent per day at 6:1 for natural gas)	**35.9**	**38.1**	**37.1**	**36.1**	**36.8**	34.5	32.8	36.4	35.7	34.9
Average sales price [1]										
Natural gas (dollars per thousand cubic feet)	**6.54**	**6.77**	**6.49**	**7.02**	**6.70**	7.54	6.63	6.07	5.53	6.42
Natural gas [a] (dollars per thousand cubic feet)	**6.59**	**6.84**	**6.53**	**6.98**	**6.73**	7.59	6.65	6.04	5.51	6.42
Natural gas liquids (dollars per barrel)	**38.13**	**43.53**	**42.06**	**46.46**	**42.82**	41.65	33.45	33.50	35.45	36.08
Crude oil – conventional (dollars per barrel)	**44.14**	**47.08**	**55.43**	**55.26**	**50.41**	47.75	37.82	38.31	36.91	40.29

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2004	**June 30 2004**	**Sept 30 2004**	**Dec 31 2004**	**2004**	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	2003
ENERGY MARKETING AND REFINING – CANADA										
Refined product sales (thousands of cubic metres per day)	**15.2**	**15.5**	**15.3**	**15.6**	**15.4**	15.7	14.9	15.2	14.2	15.0
Margins										
Refining (7) (cents per litre)	**7.8**	**7.4**	**8.8**	**7.9**	**8.0**	7.5	4.7	6.5	7.0	6.5
Refining (7), (a) (cents per litre)	**7.8**	**8.0**	**8.8**	**7.8**	**8.1**	7.8	4.2	6.4	6.9	6.4
Retail (8) (cents per litre)	**5.0**	**4.3**	**3.7**	**4.5**	**4.4**	7.0	6.2	7.0	6.3	6.6
Utilization of refining capacity (%)	**108**	**85**	**104**	**101**	**100**	103	100	91	86	95
REFINING AND MARKETING – U.S.A. (c)										
Refined product sales (thousands of cubic metres per day)	**8.1**	**8.9**	**10.9**	**9.5**	**9.3**	—	—	9.8	8.6	9.1
Margins										
Refining (7) (cents per litre)	**5.0**	**9.0**	**5.1**	**7.7**	**6.7**	—	—	7.9	4.6	5.9
Refining (7), (a) (cents per litre)	**5.0**	**9.3**	**5.3**	**7.7**	**6.8**	—	—	7.9	4.6	5.9
Retail (8) (cents per litre)	**5.0**	**6.2**	**4.2**	**6.0**	**5.4**	—	—	6.4	4.8	5.6
Utilization of refining capacity (%)	**85**	**86**	**99**	**100**	**92**	—	—	101	96	98

(a) Excludes the impact of hedging activities.
(b) Currently all Natural Gas production is located in the Western Canada Sedimentary Basin.
(c) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

Definitions

(1) Average sales price – Calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).
(2) Cash operating costs – base operations – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on production volumes. For a reconciliation of this non GAAP financial measure see page 52 of MD&A.
(3) Total cash operating costs – base operations – Include cash operating costs – base operations as defined above and cash start-up costs for in-situ operations. Per barrel amounts are based on mining production volumes.
(4) Total operating costs – base operations – Include total cash operating costs – base operations as defined above and non-cash operating costs. Per barrel amounts are based on mining production volumes.
(5) Cash operating costs – Firebag – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes.
(6) Total operating costs – Firebag – Include cash operating costs – Firebag as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes.
(7) Refining margin – Calculated as the average wholesale unit price from all products less average unit cost of crude oil.
(8) Retail margin – Calculated as the average street price of Sunoco (Energy, Marketing and Refining – Canada) and Phillips 66-branded (Refining and Marketing – U.S.A.) retail gasoline net of federal excise tax and other adjustments, less refining gasoline transfer price.

Metric conversion

Crude oil, refined products, etc. – 1m^3 (cubic metre) = approx. 6.29 barrels
Natural gas – 1m^3 (cubic metre) = approx. 35.49 cubic feet

five-year financial summary (unaudited)

($ millions except for ratios)	**2004**	2003[a]	2002	2001	2000
Revenues					
Oil Sands	**3 596**	3 061	2 616	1 372	1 402
Natural Gas	**567**	512	339	481	458
Energy Marketing and Refining – Canada	**3 460**	2 936	2 508	2 673	2 604
Refining and Marketing – U.S.A.	**1 495**	515	—	—	—
Corporate and eliminations	**(497)**	(453)	(431)	(232)	(980)
	8 621	6 571	5 032	4 294	3 484
Net earnings (loss)					
Oil Sands	**995**	888	782	273	303
Natural Gas	**115**	120	34	116	95
Energy Marketing and Refining – Canada	**80**	53	61	79	80
Refining and Marketing – U.S.A.	**34**	18	—	—	—
Corporate and eliminations	**(124)**	(4)	(128)	(92)	(117)
	1 100	1 075	749	376	361
Cash flow from (used in) operations					
Oil Sands	**1 752**	1 803	1 475	486	655
Natural Gas	**319**	298	164	280	238
Energy Marketing and Refining – Canada	**188**	164	112	165	174
Refining and Marketing – U.S.A.	**59**	34	—	—	—
Corporate and eliminations	**(297)**	(220)	(311)	(100)	(109)
	2 021	2 079	1 440	831	958
Capital and exploration expenditures					
Oil Sands	**1 118**	948	617	1 479	1 808
Natural Gas	**279**	183	163	132	127
Energy Marketing and Refining – Canada	**228**	122	60	54	45
Refining and Marketing – U.S.A.	**190**	31	—	—	—
Corporate	**31**	32	37	13	18
	1 846	1 316	877	1 678	1 998
Total assets	**11 804**	10 501	9 011	8 430	7 174
Capital employed [b]					
Short-term and long-term debt, less cash and cash equivalents	**2 159**	2 091	2 671	3 143	2 235
Shareholders' equity	**4 897**	4 355	3 397	2 731	2 435
	7 056	6 446	6 068	5 874	4 670
Less capitalized costs related to major projects in progress	**(1 467)**	(1 122)	(511)	(3 691)	(2 497)
	5 589	5 324	5 557	2 183	2 173
Total Suncor employees (number at year-end)	**4 605**	4 231	3 422	3 307	3 043

five-year financial summary (unaudited) (continued)

	2004	2003 [(a)]	2002	2001	2000
Dollars per common share					
Net earnings attributable to common shareholders	**2.40**	2.41	1.61	0.76	0.74
Cash dividends	**0.23**	0.1925	0.17	0.17	0.17
Cash flow from operations	**4.46**	4.62	3.22	1.87	2.16
Cash flow from operations after deducting dividends paid on preferred securities	**4.44**	4.52	3.11	1.76	2.06
Ratios					
Return on capital employed (%) [(c)]	**19.1**	18.4	14.6	17.7	16.3
Return on capital employed (%) [(d)]	**16.2**	16.0	13.7	7.3	9.1
Return on shareholders' equity (%) [(e)]	**23.8**	27.7	24.4	14.6	16.0
Debt to debt plus shareholders' equity (%) [(f)]	**31.4**	36.3	44.2	53.5	48.1
Net debt to cash flow from operations (times) [(g)]	**1.1**	1.0	1.9	3.8	2.3
Interest coverage – cash flow basis (times) [(h)]	**14.7**	15.7	10.6	5.9	9.0
Interest coverage – net earnings basis (times) [(i)]	**11.6**	13.5	8.1	3.6	5.4

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

(b) Capital employed – the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable).

(c) Net earnings adjusted for after-tax financing expenses (income) for the 12-month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents at the beginning and end of the year, divided by two, less average capitalized costs related to major projects in progress (as applicable). Return on capital employed (ROCE) for Suncor operating segments presented in the Quarterly Summary is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non GAAP financial measure see page 51 of MD&A.

(d) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

(e) Net earnings as a percentage of average shareholders' equity. Average shareholders' equity is the sum of total shareholders' equity at the beginning and end of the year divided by two.

(f) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

(g) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended.

(h) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(i) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

share trading information (unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU. The following share trading information reflects a two-for-one split of the company's common shares during 2002.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2004	**June 30 2004**	**Sept 30 2004**	**Dec 31 2004**	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003
Share ownership								
Average number outstanding, weighted monthly (thousands) [a]	**452 123**	**452 283**	**452 565**	**453 900**	449 187	449 485	449 756	450 505
Share price (dollars)								
Toronto Stock Exchange								
High	**38.02**	**36.80**	**41.49**	**44.49**	27.50	26.60	27.14	32.85
Low	**31.62**	**30.95**	**32.80**	**38.20**	23.87	23.31	24.75	25.07
Close	**35.97**	**34.01**	**40.40**	**42.40**	25.61	25.34	24.93	32.50
New York Stock Exchange – US$								
High	**28.75**	**28.09**	**32.63**	**36.15**	18.50	19.68	19.59	25.42
Low	**24.68**	**22.55**	**24.90**	**31.16**	15.32	16.10	17.86	18.57
Close	**27.35**	**25.61**	**32.01**	**35.40**	17.47	18.75	18.55	25.06
Shares traded (thousands)								
Toronto Stock Exchange	**100 401**	**109 073**	**102 460**	**86 424**	83 756	67 815	64 875	93 538
New York Stock Exchange	**45 120**	**59 254**	**64 519**	**66 536**	23 600	23 369	21 725	27 138
Per common share information (dollars)								
Net earnings attributable to common shareholders	**0.48**	**0.44**	**0.74**	**0.73**	0.84	0.27	0.63	0.67
Cash dividends	**0.05**	**0.06**	**0.06**	**0.06**	0.0425	0.05	0.05	0.05

(a) The company had approximately 2,375 holders of record of common shares as at January 31, 2005.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

supplemental financial and operating information (unaudited)

	2004	2003	2002	2001	2000
OIL SANDS					
Production (thousands of barrels per day)	**226.5**	216.6	205.8	123.2	113.9
Sales (thousands of barrels per day)					
Light sweet crude oil	**114.9**	112.3	104.7	56.2	64.3
Diesel	**27.9**	26.3	23.0	14.8	9.3
Light sour crude oil	**75.1**	73.3	68.3	42.0	35.8
Bitumen	**8.4**	6.4	9.3	8.5	6.2
	226.3	218.3	205.3	121.5	115.6
Average sales price (dollars per barrel)					
Light sweet crude oil	**45.60**	40.26	37.56	34.17	35.31
Other (diesel, light sour crude oil and bitumen)	**39.13**	33.93	29.58	24.86	27.09
Total	**42.28**	37.19	33.65	29.17	31.67
Total [(a)]	**49.78**	40.22	36.94	34.21	41.29
Cash operating costs – base operations [(b)]	**11.95**	11.45	11.15	11.35	11.50
Total cash operating costs – base operations [(b)]	**12.25**	11.45	11.15	11.35	11.50
Total operating costs – base operations [(b)]	**18.35**	17.25	17.25	16.70	17.25
Cash operating costs – Firebag [(b), (e)]	**19.50**				
Total operating costs – Firebag [(b), (e)]	**25.50**				
Capital employed excluding major projects in progress	**4 169**	4 050	4 512	1 378	1 402
Return on capital employed (%) [(c)]	**22.9**	20.8	16.7	19.6	22.1
Return on capital employed (%) [(d)]	**18.8**	17.4	15.6	6.2	10.2

(a) Excludes the impact of hedging activities.

(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 95.

(c) See definitions on page 97.

(d) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

(e) Firebag commenced commercial operations on April 1, 2004.

	2004	2003	2002	2001	2000
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**200**	187	179	177	200
Net	**147**	142	124	124	142
Natural gas liquids (thousands of barrels per day)					
Gross	**2.5**	2.3	2.4	2.4	3.0
Net	**1.8**	1.7	1.7	1.7	2.1
Crude oil (thousands of barrels per day)					
Gross	**1.0**	1.4	1.5	1.5	4.2
Net	**0.8**	1.1	1.2	1.1	3.3
Total (thousands of boe [(a)] per day)					
Gross	**36.8**	34.9	33.7	33.4	40.5
Net	**27.1**	26.4	23.6	23.5	29.1
Average sales price					
Natural gas (dollars per thousand cubic feet)	**6.70**	6.42	3.91	6.09	4.72
Natural gas (dollars per thousand cubic feet) [(b)]	**6.73**	6.42	3.91	6.12	4.73
Natural gas liquids (dollars per barrel)	**42.82**	36.08	29.35	34.38	36.66
Crude oil – conventional (dollars per barrel)	**50.41**	40.29	31.72	33.92	29.50
Capital employed	**448**	400	422	291	387
Return on capital employed (%) [(e)]	**27.1**	29.2	9.5	34.2	17.8
Undeveloped landholdings [(c)]					
Oil and gas (millions of acres)					
Western Canada					
Gross	**0.7**	0.5	0.5	0.6	1.4
Net	**0.5**	0.4	0.4	0.5	1.1
International					
Gross	**0.7**	0.9	1.2	1.7	1.3
Net	**0.4**	0.2	0.7	1.3	1.1
Net wells drilled [(d)]					
Exploratory					
Oil	**—**	—	—	—	—
Gas	**5**	2	2	4	1
Dry	**5**	31	19	16	15
Development					
Oil	**—**	1	—	—	2
Gas	**16**	16	18	16	14
Dry	**—**	4	4	2	3
	26	54	43	38	35

(a) Barrel of oil equivalent – converts natural gas to oil on the approximate energy equivalent basis that 6,000 cubic feet equals one barrel of oil.

(b) Excludes the impact of hedging activities.

(c) Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres.

(d) Excludes interests in eleven net exploratory wells and three net development wells in progress at the end of 2004.

(e) See definitions on page 97.

	2004	2003	2002	2001	2000
ENERGY MARKETING AND REFINING – CANADA					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail [b]	**4.6**	4.4	4.5	4.3	4.2
Other	**4.1**	4.2	4.4	4.4	4.0
Jet fuel	**0.9**	0.7	0.4	0.7	1.1
Diesel	**3.1**	3.0	2.9	3.1	3.1
	12.7	12.3	12.2	12.5	12.4
Petrochemicals	**0.8**	0.8	0.6	0.5	0.6
Heating oils	**0.4**	0.5	0.4	0.4	0.4
Heavy fuel oils	**0.7**	0.8	0.6	0.8	0.6
Other	**0.8**	0.6	0.7	0.6	0.6
	15.4	15.0	14.5	14.8	14.6
Margins (cents per litre)					
Refining	**8.0**	6.5	4.8	5.7	5.9
Refining [c]	**8.1**	6.4	4.8	5.7	5.9
Retail	**4.4**	6.6	6.6	6.6	6.6
Crude oil supply and refining					
Processed at Sarnia refinery (thousands of cubic metres per day)	**11.1**	10.5	10.6	10.2	10.9
Utilization of refining capacity (%)	**100**	95	95	92	98
Capital employed excluding major projects in progress	**512**	551	485	480	384
Return on capital employed (%) [d]	**14.6**	10.3	12.0	18.3	20.3
Return on capital employed (%) [d], [e]	**13.6**	10.3	12.0	18.3	20.3
Retail outlets [f] (number at year-end)	**385**	379	384	400	402

supplemental financial and operating information (unaudited) (continued)

	2004	2003	2002	2001	2000
REFINING AND MARKETING – U.S.A. [a]					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail [b]	**0.7**	0.7	—	—	—
Other	**3.8**	3.5	—	—	—
Jet fuel	**0.5**	0.5	—	—	—
Diesel	**2.2**	2.3	—	—	—
	7.2	7.0	—	—	—
Asphalt	**1.5**	1.7	—	—	—
Other	**0.6**	0.4	—	—	—
	9.3	9.1	—	—	—
Margins (cents per litre)					
Refining	**6.7**	5.9	—	—	—
Refining [c]	**6.8**	5.9	—	—	—
Retail	**5.4**	5.6	—	—	—
Crude oil supply and refining					
Processed at Denver refinery (thousands of cubic metres per day)	**8.8**	9.4	—	—	—
Utilization of refining capacity (%)	**92**	98	—	—	—
Capital employed excluding major projects in progress	**232**	270			
Return on capital employed (%) [d], [h]	**12.2**	—			
Return on capital employed (%) [d], [e]	**11.0**	—			
Retail outlets [g] (number at year-end)	**43**	43	—	—	—

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

(b) Excludes sales through joint-venture interests.

(c) Excludes the impact of hedging activities.

(d) See definitions on page 97.

(e) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

(f) Sunoco-branded service stations, other private brands managed by EM&R and EM&R's interest in service stations managed through joint-ventures. Outlets are located mainly in Ontario.

(g) Phillips 66-branded service stations. Outlets are primarily located in the Denver, Colorado area.

(h) For 2003, represents five months of operations since acquisition August 1, 2003 therefore no annual ROCE was calculated.

investor information

Stock Trading Symbols and Exchange Listing
Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

Dividends
Suncor's Board of Directors reviews its dividend policy quarterly. Effective the second quarter of 2004, dividends were increased to $0.06 per share from $0.05 per share resulting in an aggregate 2004 dividend of $0.23 per common share.

Dividend Reinvestment and Common Share Purchase Plan
Suncor's Dividend Reinvestment and Common Share Purchase Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through optional cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. To obtain additional information, call Computershare Trust Company of Canada at 1-877-982-8760 or visit www.computershare.com. Information regarding the purchase plan is also available at www.suncor.com.

Stock Transfer Agent and Registrar
In Canada, Suncor's agent is Computershare Trust Company of Canada. In the United States, Suncor's agent is Computershare Trust Company, Inc.

Independent Auditors
PricewaterhouseCoopers LLP

Independent Reserve Evaluators
Gilbert Laustsen Jung Associates Ltd.

Annual Meeting
Suncor's annual and special meeting of shareholders will be held at 10:30 a.m. MST on April 28, 2005 at the Metropolitan Centre, 333 Fourth Avenue S.W., Calgary, Alberta. Presentations from the meeting will be web cast live at www.suncor.com.

Corporate Office
Box 38, 112 – 4th Avenue S.W., Calgary, Alberta, T2P 2V5
Telephone: 403-269-8100 Toll free number: 1-866-SUNCOR-1
Facsimile: 403-269-6217 E-mail: info@suncor.com

Analyst and Investor Inquiries
John Rogers, vice president, Investor Relations
Telephone: (403) 269-8670 Facsimile: (403) 269-6217 Email: invest@suncor.com

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Sometimes our shareholders receive more than one copy of our Annual Report. If you receive but do not require more than one mailing, call Computershare Trust Company of Canada at 1-877-982-8760. Computershare will update your account information accordingly.

Shareholders can help reduce mailing costs and paper waste by electing to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, registered shareholders should visit www.computershare.com. Beneficial shareholders (shareholders holding shares through a broker) should go to www.investordeliverycanada.com and follow the instructions for enrollment.

corporate directors and officers

Providing strategic guidance to the company, setting policy direction and ensuring Suncor is fairly reporting its progress are central to the work of Suncor's Board of Directors.

The Board's oversight role encompasses Suncor's strategic planning process, risk management, communication with investors and other stakeholders and standards of business conduct. Suncor's Board is also responsible for selecting, monitoring and evaluating executive leadership and aligning management's decision making with long-term shareholder interest. There are no significant differences between Suncor's governance practices and those prescribed by the New York Stock Exchange (NYSE), with the exception of the requirements applicable to equity compensation plans. A comprehensive description of Suncor's governance practices, including differences between Toronto Stock Exchange (TSX) and NYSE requirements related to equity compensation plans, is available in the company's Management Proxy Circular in the investor centre, financial reports and disclosure section of Suncor's website at www.suncor.com or by calling 1-800-558-9071.

Sarbanes-Oxley
For the year ended December 31, 2004, Suncor has voluntarily complied with the reporting, certification and attestation provisions under the United States Sarbanes-Oxley Act, Section 404.

Independence
As of December 31, 2004, Suncor's Board of Directors comprises thirteen directors, eleven of whom have been determined by the Board to be independent of management under the guidelines established by the TSX and NYSE. The role of chair is assumed by an independent director and is separate from the role of chief executive officer. Independent directors also chair the four committees of the Board.

Committee	Key Responsibilities
Board Policy, Strategy Review and Governance Committee*	Oversees key matters pertaining to Suncor's values, beliefs and standards of ethical conduct. Reviews key matters pertaining to governance, including organization, composition and effectiveness of the Board. Reviews preliminary stages of key strategic initiatives and projects. Reviews and assesses processes relating to long range and strategic planning and budgeting.
Human Resources and Compensation Committee*	Reviews and ensures Suncor's overall goals and objectives are supported by appropriate executive compensation philosophy and programs; annually evaluates the performance of the chief executive officer (CEO) against predetermined goals and criteria, and recommends to the Board the total compensation for the CEO. The committee also annually reviews the CEO's evaluation and recommendations for total compensation of the other executive roles; the executive succession planning process and results, and all major human resources programs.
Environment, Health and Safety (EH&S) Committee	Reviews the effectiveness with which Suncor meets its obligations pertaining to environment, health and safety including the establishment of appropriate policies with regard to legal, industry and community standards and related management systems and compliance.
Audit Committee*	Assists the Board in matters relating to Suncor's internal controls, internal and external auditors and the external audit process, oil and natural gas reserves reporting, financial reporting and public communication and certain other key financial matters. Provides an open avenue of communication between management, the internal and external auditors and the Board. Approves Suncor's interim financial statements and management's discussion and analysis.

*comprised entirely of independent directors as of December 31, 2004.

Share Ownership
The Board has set guidelines for its own, as well as executive share ownership. Shares held by each Board member and guidelines for Board and executive share ownership are reported annually in Suncor's Management Proxy Circular.

board of directors

JR Shaw [2,3]

Calgary, Alberta
Chairman of the Board of Directors
Director since 1998

JR Shaw has been the chairman of the Board of Suncor since 2001. He is also the executive chair of Shaw Communications Inc., the company he founded in 1966. Mr. Shaw has served as a director of several Canadian companies and is also a director of the Shaw Foundation. In 2003, Mr. Shaw was named an Officer of the Order of Canada.

Mel E. Benson [3,4]

Calgary, Alberta
Director since 2000

Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta and a director of Pan Global Ventures Energy Ltd. From 1996 to 2000, Mr. Benson was the senior operations advisor, African Development, Exxon Co. International. Mr. Benson is an active member of several charitable and Aboriginal organizations. He is a member of the Council for Advancement of Native Development Officers and the Canadian Aboriginal Professional Association. He is also chair of the Northern Alberta Institute of Technology's Aboriginal Education Success Initiative.

Brian A. Canfield [2,3]

Point Roberts, Washington
Chair, Human Resources and Compensation Committee
Director since 1995

Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Mr. Canfield also serves as a director of Terasen Inc. and a director and member of the governance committee of the Canadian Public Accountability Board. In 1998, Mr. Canfield was appointed to the Order of British Columbia.

Susan E. Crocker [2,3]

Toronto, Ontario
Director 2003 to 2005

Susan Crocker, a director of Suncor since April 24, 2003, has advised the company she will not run for re-election to the Board. During her tenure with Suncor, Ms. Crocker was employed as a corporate director and management consultant. From 1999 to 2001, she was the president and chief executive officer of the Hospitals of Ontario Pension Plan and, from 1996 to 1999, she was senior vice president, equity and derivative markets with the TSX.

Bryan P. Davies [1,4]

Toronto, Ontario
Director 1991 to 1996 and since 2000

Bryan Davies is superintendent of the Financial Services Commission of Ontario. Prior to assuming this role, Mr. Davies served as senior vice president of regulatory affairs with the Royal Bank Financial Group and was vice president, business affairs and chief administrative officer of the University of Toronto. He worked for the Government of Ontario holding a variety of positions, including deputy minister positions in several departments. Mr. Davies is also active with numerous not-for-profit and charitable organizations. He is chair of the Canadian Merit Scholarship Foundation and a director of the Foundation for International Training.

Brian A. Felesky [1,4]

Calgary, Alberta
Director since 2002

Brian Felesky is a partner in the law firm of Felesky Flynn LLP in Calgary, Alberta. Mr. Felesky also serves as a director of TransCanada Power LP, where he is chair of the audit committee. Mr. Felesky is actively involved in not-for-profit and charitable organizations. He is the co-chair of Homefront on Domestic Violence, vice chair of the Canada West Foundation, member of the senate of Notre Dame College, member of the Board of Governors of the Council for Canadian Unity and a director of three private companies.

John T. Ferguson [1,2]

Edmonton, Alberta
Chair, Audit Committee
Director since 1995

John Ferguson is chairman of the Board of Princeton Developments Ltd., a real estate company in Edmonton, Alberta, and chair of the Board of TransAlta Corporation in Calgary, Alberta. Mr. Ferguson is also a director of Bellanca Developments Ltd. and the Royal Bank of Canada. He is a director of the C.D. Howe Institute, an advisory member of the Canadian Institute for Advanced Research, and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is also a fellow of the Alberta Institute of Chartered Accountants.

W. Douglas (Doug) Ford [1,4]

Downers Grove, Illinois
Director since 2004

Doug Ford was chief executive, refining and marketing, for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of the company as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation, United Airlines Corporation and Air Products and Chemicals, Inc. He is also a member of the Board of Trustees of the University of Notre Dame.

Richard (Rick) L. George

Calgary, Alberta
Director since 1991

Rick George is the president and chief executive officer of Suncor Energy Inc. Mr. George is also a Board member of the U.S. offshore and onshore drilling company, GlobalSantaFe Corporation and serves as chairman of the Canadian Council of Chief Executives.

board of directors (continued)

John R. Huff [2,3]

Houston, Texas
Chair, Board Policy, Strategy Review and Governance Committee
Director since 1998

John Huff is chairman and chief executive officer of Oceaneering International Inc., an oil field services company. Mr. Huff is also a director of BJ Services Company. He is active in a variety of non-profit organizations, serving as a director for the American Bureau of Shipping and the Marine Resources Foundation, Key Largo and as a trustee for the Houston Museum of Natural Science.

Robert W. Korthals [1]

Toronto, Ontario
Director since 1996

Robert Korthals is the former president of the Toronto-Dominion Bank. Mr. Korthals is currently chairman of the Board of the Ontario Teachers' Pension Plan Board. He is a director of Bucyrus International, Inc., Great Lakes Carbon Income Trust, Jannock Properties Limited, Rogers Communications Inc., easyHome Inc., Cognos Inc. and several publicly traded investment funds sponsored by Mulvihill Investments. In addition, Mr. Korthals serves as a director of the Canadian Parks and Wilderness Foundation.

M. Ann McCaig [3,4]

Calgary, Alberta
Chair, Environment, Health and Safety Committee
Director since 1995

Ann McCaig is chair of the Alberta Adolescent Recovery Centre and a trustee of the Killam Estate. She is co-chair of the Alberta Children's Hospital Foundation $50 million All for One – All for Kids campaign. Ms. McCaig has been an active member of the community with many local and national organizations including United Way, Banff Centre Foundation and chair of the City of Calgary Police Interpretative Centre. For 14 years she served on the University of Calgary's board of governors, was named chancellor, and in 1998, earned the distinction of chancellor emeritus. In 2005, Ms. McCaig was named a Member of the Order of Canada.

Michael W. O'Brien [4]

Canmore, Alberta
Director since 2002

Michael O'Brien served as executive vice president, Corporate Development and chief financial officer of Suncor Energy Inc. before his retirement in 2002. Prior to that, Mr. O'Brien was executive vice president of Suncor's wholly-owned subsidiary, Suncor Energy Products Inc. (formerly Sunoco Inc.) from 1992 to 2000. Mr. O'Brien also serves on the Boards of PrimeWest Energy Inc., Terasen Inc. and Shaw Communications Inc. As well, he is past chair for Canada's Climate Change Voluntary Challenge and Registry Inc., the Canadian Petroleum Products Institute and the Nature Conservancy Canada.

(1) Audit Committee
(2) Board Policy, Strategy Review and Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health and Safety Committee

In 2004, the Board of Directors met six times. Committees of the Board generally meet four to six times per year with the exception of the Audit Committee, which meets more frequently. With the exception of one Board member absent from one committee meeting, all members attended all board and committee meetings in 2004.

For further information about Suncor's corporate governance practices and the company's code of corporate conduct, visit www.suncor.com or call 1-800-558-9071 to order a copy of the company's Management Proxy Circular.

officers

Richard L. George
President and
Chief Executive Officer

J. Kenneth Alley
Senior Vice President
and Chief Financial Officer

M. (Mike) Ashar
Executive Vice President,
Refining and Marketing – U.S.A.

David W. Byler
Executive Vice President,
Natural Gas and Renewable Energy

Robert F. Froese
Treasurer

Terrence J. Hopwood
Senior Vice President
and General Counsel

Sue Lee
Senior Vice President, Human
Resources and Communications

Kevin D. Nabholz
Executive Vice President,
Major Projects

Janice B. Odegaard
Vice President, Associate General
Counsel and Corporate Secretary

Thomas L. Ryley
Executive Vice President, Energy
Marketing and Refining – Canada

Steven W. Williams
Executive Vice President,
Oil Sands

Offices shown are positions held by the officers in relation to business units of Suncor Energy Inc. and its subsidiaries on a consolidated basis. On a legal entity basis, Mr. Ashar is president of Suncor Energy (U.S.A.) Inc., Suncor's U.S. based downstream subsidiary; Mr. Ryley is president of Suncor's Canada-based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc.; and Mr. Nabholz is executive vice president of Suncor Energy Services Inc., which provides major projects management and other shared services to the Suncor group of companies.

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Member of Dow Jones Sustainability Indexes
DJSI

The Dow Jones Sustainability Index (DJSI) follows a best-in-class approach comprising the sustainability leaders from each industry. Suncor has been part of the index since the DJSI was launched in 1999.

Imagine Caring Company
Une entreprise généreuse

As an Imagine Caring Company, Suncor contributes 1% of its pretax profit to registered charities.

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Box 38, 112 – 4th Avenue S.W., Calgary, Alberta T2P 2V5
tel: (403) 269-8100 fax: (403) 269-6217 info@suncor.com www.suncor.com